APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION

FOR A CERTIFICATE OF NEED

BLUE LAKE GENERATING PLANT EXPANSION PROJECT

PUC DOCKET NO. E002/CN-04-___

JANUARY 16, 2004

Xcel Energy
NORTHERN STATES POWER

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Kenneth Nickolai	Commissioner
Phyllis Reha	Commissioner
Gregory Scott	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR A CERTIFICATE OF NEED FOR THE ADDITION OF TWO, 160 MEGAWATT, COMBUSTION TURBINE GENERATORS AT THE BLUE LAKE POWER PLANT SITE.

DOCKET NO. E002/CN-04-___

FILING SUMMARY

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "Company") filed an application with the Minnesota Public Utilities Commission ("Commission") on January 16, 2004 for a Certificate of Need to add two, 160-megawatt, natural gas fueled combustion turbines at the Blue Lake generating plant site in Shakopee, Minnesota to be placed in service in 2005.

The Project would consist of the installation of two simple cycle, gas-fired, combustion turbine generators adjacent to existing simple cycle oil-fired combustion turbines at the Blue Lake Generating Plant, the construction of 230/115 KV transmission line interconnection approximately 1200 feet long between the Blue Lake Substation and an existing 230 kV transmission line, and an approximately 10 to 12 mile long natural gas pipeline to connect the Project to regional gas supply to the south.

Xcel Energy has encountered significant challenges as we attempt to arrange the power supply purchases necessary to meet anticipated peak demand for electricity from our customers in 2005.

Recently encountered limitations and constraints on the regional transmission system have created considerable uncertainty in our ability to make sufficient short term power supply purchases that we have traditionally relied on to meet peak electrical demand and associated reserve obligations designed to ensure system reliability.

Regional transmission constraints and other issues have also presented difficulties in our longer-term power supply purchase program. As the result, resources originally anticipated to be available in 2005 will be delayed and may need to be replaced.

This proposed Project, along with another combustion turbine generator we have proposed at the Angus Anson Generating Plant near Sioux Falls, are necessary to ensure that Xcel Energy has adequate generating capacity in 2005 and beyond to reliably meet customer demand for electricity.

Copies of our application can be obtained from our web site at www.xcelenergy.com. Alternatively you may contact James Alders at 612 330 6732 or at james.r.alders@xcelenergy.com.

January 16, 2004

Cc: Xcel Energy's general electric service list

Xcel Energy's Resource Plan service list (Docket E002/RP-02-2065)

Certificate of Need Application
for the
Blue Lake Generating Plant Expansion Project

Table of Contents

List of Tables

List of Figures

Appendices

Appendix A	Air Emissions Modeling
Appendix B	Xcel Energy System Demand and Capability Data
Appendix C	Xcel Energy Demand Side Management Programs
Appendix D	Alternative Technologies Screening

APPLICATION FOR CERTIFICATE OF NEED
Content Requirement and Completeness Checklist

Authority	Required Information	Location of Required Content
7849.0120A	Showing that denial would adversely affect adequacy, reliability and efficiency	Chapter 1
1	Demand forecast for type of energy supplied by proposed facility is accurate	Appendix B
2	Effects of applicant's conservation program and state and federal conservation programs	§ 1.3.1, § 5.1.2, § 6.3.1
3	Effects of applicant's promotional practices on energy demand	§ 5.1.2
4	Ability of current facilities and facilities not requiring certificate of need to meet future demand	Chapter 6
5	Effect of proposed facility in making efficient use of resources	Chapter 6, § 7.4
7849.0120B	A more reasonable and prudent alternative has not been demonstrated	Chapter 1, Chapter 6
1	Appropriate size, type and timing compared to reasonable alternatives	Chapter 6
2	Cost of facility and of its energy compared to reasonable alternatives	§ 6.4.4, § 6.4.5
3	Effects on natural and socioeconomic environment vs. reasonable alternatives	§ 4.6, Chapter 7
4	Expected reliability of facility compared to reasonable alternatives	§ 6.6.3
7849.0120C	Project benefit society by protecting the natural and socioeconomic environment, including human health, considering:	Chapter 7
1	Relationship of facility to overall state energy needs	§ 1.3.4, § 7.1 Chapter 8
2	Effects of facility on natural and socioeconomic environment compared to not building facility	Chapter 7
3	Effects of facility inducing future development	§ 7.9
4	Socially beneficial uses of the output of the facility, including to protect or enhance environmental quality	§ 7.6

Authority	Required Information	Location of Required Content
7849.0120D	Project will comply with relevant policies and regulations of other state and federal agencies and local governments	Chapter 8
7849.0200	Application procedures and timing	Cover Letter
7849.0210	Filing fee to accompany application	Cover Letter
7849.0220	Contents of application	Table of Contents; Content Requirements Checklist
7849.0230	Draft environmental report	Not applicable to LEGF; Prepared by PUC using information provided
7849.0240	Need Summary and Additional Considerations	Chapter 1
7849.0240, Subp. 1	Need summary contains major factors that justify need for facility	Chapter 1
7849.0240, Subp. 2A	Additional considerations address socially beneficial uses of facility output, including uses to protect or enhance environmental quality	§ 4.4; Chapter 6; Chapter 8
7849.0240, Subp. 2B	Promotional activities that may have given rise to demand	§ 5.1.2
7849.0240 Subp. 2C	Effects of the facility in inducing future development	§ 7.8, § 7.9
7849.0250	Description of proposed LEGF and alternatives	Chapter 3; Chapter 6; Appendix D
A	Description of the facility, including:	Chapter 3
1	Nominal generating capability and economies of scale on the facility size and timing	§ 3.1; § 6.3.6
2	Anticipated operating cycle including expected annual capacity factor	§ 3.6.1, Table 3-1
3	Type of fuel used, including reason for choice of fuel, availability of fuel and alternative fuels, if any	§ 1-2, § 3-4, Table 3-1
4	Anticipated heat rate of the facility	Table 3-1
5	Anticipated areas where the proposed facility could be located	§ 1-1
B	Discuss alternatives available	Chapter 6
1	Purchased power	§ 6.3.3, § 6.3.4

Authority	Required Information	Location of Required Content
2	Increased efficiency of existing facilities, including transmission lines	§ 6.3.2
3	New transmission lines	§ 6.3.5
4	New generating facilities of a different size or using a different energy source as fuel	§ 6.3.6, § 6.3.7, § 6.4
5	Any reasonable combinations of the alternatives listed in items 1-4	§ 6.2
C	For the facility and for each alternative in B that could provide electric power at the asserted level of need, discuss:	Table 6-5
1	Capacity cost in current $/kW	Table 6-5
2	Service life	§ 3-2
3	Estimated average annual availability	§ 6.1.2, § 6.3, Table 6-6
4	Fuel costs in current $/kWh	§ 6-5, Table 3-1, Table 6-7
5	Variable operating and maintenance costs in current $/kWh	§ 3-6-3
6	Total cost in current $/kWh	Table 3-2
7	Estimated rate impact, system wide and in Minnesota, assuming a test year beginning with the proposed in-service date	Table 3-2
8	Efficiency, expressed for a generating facility as the estimated heat rate, or for a transmission facility as estimated losses under maximum and average loading conditions	Table 3-1
9	Major assumptions in providing the information in items 1-8, including projected escalation rates for fuel costs, O&M costs, and capacity factors	Appendix A
D	Map showing the applicant's system	Figure 2-1
E	Such other relevant information about the proposed facility and each alternative as may be relevant to need determination	Application
7849.0270-0290	System load, annual consumption forecast, capacity and conservation program information	§ 5.1, Appendix B
7849.0270	Peak Demand and Annual Consumption Forecast	Appendix B, § B.10

Authority	Required Information	Location of Required Content
7849.0270 subpt. 1	Pertinent data concerning peak demand and annual electrical consumption	Appendix B, § B.10
7849.0270 subpt. 2	Provide the following data for each forecast year:	
A	Annual consumption by consumers within the MN service area	§ 5.1, Appendix B, § B.10
B	Estimates of number of consumers and their annual consumption for:	Appendix B, § B.10
(1)	Farm, excluding irrigation and drainage pumping	Appendix B § B.10
(2)	Irrigation and drainage pumping	Appendix B § B.10
(3)	Nonfarm residential	Appendix B § B.10
(4)	Commercial	Appendix B § B.10
(5)	Mining	Appendix B § B.10
(6)	Industrial	Appendix B § B.10
(7)	Street and highway lighting	Appendix B § B.10
(8)	Electrified transportation	Appendix B, § B.10
(9)	Other	Appendix B, § B.10
(10)	Sum of sub items (1)-(9)	Appendix B, § B.10
C	Estimated power demand at annual peak demand, broken down as in B.	Appendix B, § B-10
D	System peak demand by month	Appendix B, § B.10
E	Estimated annual revenue requirement per kW-hr (in current dollars)	Table 3-2
F	Estimated average system weekday load factor by month	Appendix B, § B-10
subpt. 3	Detail of the forecast methodology employed in subpt. 2, including:	Appendix B
A	Overall methodological framework used	Appendix B, § B.1
B	Specific analytical techniques used, their purpose and where used	Appendix B, § B.2
C	Manner in which the specific techniques are related	Appendix B, § B.2

Authority	Required Information	Location of Required Content
D	Where statistical techniques have been used:	Appendix B, § B.3
(1)	Purpose of the technique	Appendix B, § B.3
(2)	Typical computations, specifying variables and data	Appendix B, § B.3
(3)	Results of appropriate statistical tests	Appendix B, § B.3
E	Forecast confidence levels or ranges for peak demand and consumption	Appendix B, § B.4
F	A brief analysis of the methodology used, including:	Appendix B, § B.5
(1)	Strengths and weaknesses	Appendix B, § B.5
(2)	Suitability to the system	Appendix B, § B.5
(3)	Cost considerations	Appendix B, § B.5
(4)	Data requirements	Appendix B, § B.5
(5)	Past accuracy	Appendix B, § B.5
(6)	Other factors considered significant	Appendix B, § B.5
G	Explanation of discrepancies between current and previous forecasts	§ 5-1, Appendix B, § B.6
subpt. 4	Discussion of the database used in current forecasting, including:	Appendix B, § B.7
A	Complete list and description of all datasets used in the forecast	Appendix B, § B.7
B	Clear identification of adjustments made to raw data including:	Appendix B, § B.8
(1)	Nature of adjustment	Appendix B, § B.8
(2)	Reason for adjustment	Appendix B, § B.8
(3)	Magnitude of adjustment	Appendix B, § B.8
subpt. 5	Discussion of each assumption made in forecast preparation, including:	Application and Appendix B
A	Availability of alternate sources of energy	Chapter 5 and Chapter 6
B	Expected conversion from other fuels to electricity or vice versa	Chapter 6, Appendix B, § B.8

Authority	Required Information	Location of Required Content
C	Future prices and their projected impact upon system demand	Chapter 5, Chapter 6, Appendix B, § B.8
D	Subpt. 2 data that is not available historically or internally generated	Appendix B, § B.8
E	Impact of energy conservation programs upon electrical demand	Appendix B, § B.8
F	Any other factor considered in preparing the forecast	Chapter 5, Chapter 6, Appendix B, § B.8
subpt. 6	Applicant shall provide:	Appendix B, § B.9
A	Description of coordination of load forecasts with other systems	Appendix B, § B.9
B	Description of the manner in which forecasts are coordinated	Appendix B, § B.9
7849.0280	Description of ability of existing system to meet forecast demand	Appendix B
A	Discussion of power planning programs applied	§ 5.1.2, § 5.1.3
B	Seasonal firm purchases and sales for each utility in each forecast year	Appendix B, Table B-1
C	Seasonal participation purchases and sales for each utility in each forecast year	Appendix B, Table B-2
D	For the summer and winter season of each forecast year:	Appendix B, Table B-3
(1)	Seasonal system demand	Appendix B, Table B-3
(2)	Annual system demand	Appendix B, Table B-3
(3)	Total seasonal firm purchases	Appendix B, Table B-3
(4)	Total seasonal firm sales	Appendix B, Table B-3
(5)	Seasonal adjusted net demand	Appendix B, Table B-3
(6)	Annual adjusted net demand	Appendix B, Table B-3
(7)	Net generating capacity	Appendix B, Table B-3
(8)	Total participation purchases	Appendix B, Table B-3
(9)	Total participation sales	Appendix B, Table B-3
(10)	Adjusted net capability	Appendix B, Table B-3

Authority	Required Information	Location of Required Content
(11)	Net reserve capacity obligation	Appendix B, Table B-3
(12)	Total firm capacity obligation	Appendix B, Table B-3
(13)	Surplus or deficit capacity	Appendix B, Table B-3
E	Load generation capacity for purchases, sales, and generation in years subsequent to application (see D 1-13)	Appendix B, Table B-4
F	Load generation capacity for projected purchases, sales and generation in years subsequent to application (see D 1-13)	Appendix B, § B.10
G	List of proposed additions and retirements in generating capacity for each forecast year subsequent to application	Appendix B, § B.10
H	Graph of monthly adjusted net demand and capability; plot of difference between capability and maintenance outages	Appendix B, § B.10
I	Appropriateness and method of determining system reserve margins	Appendix B
7849.0290	Application must include the following regarding conservation programs:	
A	Party (ies) responsible for energy conservation and efficiency programs	Appendix C, § C.1
B	List of energy conservation and efficiency goals and objectives	Appendix C, § C.2
C	Description of programs considered, implemented and rejected	Appendix C, § C.3
D	Description of major accomplishments in conservation and efficiency	Appendix C, § C.4
E	Description of future plans with respect to conservation and efficiency	Appendix C, § C.5
F	Quantification of the manner by which these programs impact the forecast	Appendix C, § C.6
7849.0300	Consequences of indefinite delay or 1,2, or 3 year postponement	§ 5.4
7849.0310	Environmental information requested	Chapter 4, Appendix A
7849.0320	Provide data for each alternative that would involve LEGF construction	Chapter 6, Appendix D

Authority	Required Information	Location of Required Content
7849.0320A	Estimated range of land requirements for the facility and a discussion of assumptions on land requirements, water storage, cooling systems, solid waste storage	Chapter 4
B	Estimated vehicular, rail, barge traffic generated by construction and operation of the facility	§ 3.4, § 4.4, § 4.6
C	For fossil-fueled facilities:	
1	Expected regional fuel sources for the facility	§ 1.1, § 2.2.4, § 3.4, Table 3-1
2	Typical fuel requirement during operation at rated capacity and annual fuel requirement at expected capacity factor	Table 3-1
3	Expected rate of heat input in Btu per hour at rated capacity	Table 3-1
4	Typical range of heat value of the fuel (in Btu/lb, Btu/gallon or Btu/1000Cf) and typical average heat value	Table 3-1
5	Typical ranges of sulfur, ash and moisture content of the fuel	Table 3-1
D	For Fossil fueled facilities:	
1	Estimated range of trace element emissions and maximum emissions of SO2, NOx, and PM in lbs/hour during operation at rated capacity	Table 6-8
2	Estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from stack of SO2, NOx and PM in micrograms/cubic meter at rated capacity and assuming generalized worst-case meteorological conditions	Table 6-8
E	Water use by the facility for alternate cooling systems, including:	Table 3-1
1	Estimated maximum use, including the groundwater pumping rate in gallons/minute and surface water appropriation in cubic feet/second	Table 3-1
2	Estimated ground water appropriation in million gallons/year	Table 3-1
3	Annual consumption in acre-feet	Table 3-1

Authority	Required Information	Location of Required Content
F	Potential sources and types of discharges to water attributable to operation of the facility	§ 4.4, Table 4-3, Table 6-6
G	Radioactive releases, including:	
1	For nuclear facilities, typical levels	N/a
2	For fossil-fueled facilities, the estimated range of radioactivity released by the facility in curies per year	Table 6-6
H	Potential types and quantities of solid wastes in tons per year at expected capacity factor	§ 4.4, Table 6-6
I	Potential sources and types of audible noise attributable to operation	§ 4.2, Table 6-6
J	Estimated work force required for construction and operation	§ 1.3.3, § 7.7, Table 6-6
K	Minimum number and size of transmission facilities required to provide reliable outlet	§ 1.1, § 3.2, § 3.4
7849.0340	Alternative of no facility	§ 6.3.8
A	Expected operation of existing and committed facilities	§ 6.3.2
B	Description of the changes in resource requirements and wastes produced	§ 4.4, Table 4-3, Chapter 5
C	Description of possible methods of reducing environmental impact	Chapter 6
Minn. Stat. § 216B.243	Certificate of Need Criteria	
Subd. 2	Certificate required for this facility	Chapter 1
Subd. 3	Showing required for construction. In assessing need, the Commission shall evaluate:	
1	Accuracy of the long-range energy demand forecast on which need is based	Chapter 5, Appendix B
2	Effect of existing or possible conservation on long-term demand	§ 1.2, § 4.4.8, Appendix C
3	Relationship of proposed facility to overall state energy needs, as described in most recent state energy policy report	§ 8.1

Authority	Required Information	Location of Required Content
4	Promotional activities that may have given rise to the demand for this facility	§ 5.1.2
5	Benefits of this facility, including uses to protect or enhance environmental quality, increase reliability of energy supply	Chapter 7
6	Possible alternatives for satisfying demand, including increased efficiency and upgrading existing generation, load-management and distributed generation	Chapter 6
7	Policies, rules and regulations of other state and federal agencies and local governments	Chapter 1, Chapter 8
8	Feasible combination of energy conservation improvements, that can replace or compete with the facility	§ 1.2, § 4.4.8, § 6.3.1
§ 216B.243 subd. 3a and § 216B.2422, subd. 4	Availability of renewable energy alternatives	§ 6.4, Appendix D

1 Summary

1.1 Unanticipated Changes in Xcel Energy's Power Supply Need to be Addressed Immediately

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy") has encountered significant challenges as we attempt to make the power supply arrangements necessary to meet anticipated peak demand for electricity from our customers in 2005.

Recently encountered limitations and constraints on the regional transmission system have created uncertainty in our ability to make sufficient short term power supply purchases that we have traditionally relied on to meet peak electrical demand and associated reserve obligations designed to ensure system reliability.

Regional transmission constraints and other issues have also presented difficulties in our longer-term power supply purchase program. As the result, resources originally anticipated to be available in 2005 will be delayed and may need to be replaced.

This proposed Project, along with another combustion turbine generator we have proposed at the Angus Anson Generating Plant near Sioux Falls, will ensure that Xcel Energy has adequate generating capacity in 2005 and beyond to reliably meet customer demand for electricity. As described throughout this Application, the proposed Project is the best available solution to meet this pressing need in a timely fashion. Many other alternatives were explored, including renewable energy options, alternative generation options, transmission options and a "no build" option. But none of them can meet the need for additional capacity and peaking energy beginning in 2005.

1.2 Certificate of Need Proposal

As a result, Xcel Energy hereby requests that the Public Utilities Commission (the "Commission") grant a

Certificate of Need (CON) pursuant to Minnesota Statutes 216B.243 and Minnesota Rules Chapter 7849 for the addition of two, 160 megawatt (nominal) generating units to the Blue Lake Electric Generating Plant in Shakopee, Minnesota and associated transmission necessary to interconnect the generators (the "Project"). The Project location is shown in Figure 1-1 and Figure 1-2.

The Project will consist of the installation of two simple cycle, natural gas-fired, combustion turbine generators (CTGs) adjacent to the four existing simple cycle oil-fired CTGs at the Xcel Energy Blue Lake Generating Plant (the "Plant"), the construction of 230/115 KV transmission line interconnection approximately 1200 feet long between the Blue Lake Substation and an existing 230 kV transmission line, and an intrastate natural gas pipeline to connect the Project to regional gas supply pipeline located approximately 10 miles south of the Plant.

In order to have the Blue Lake generation additions available for the summer of 2005, construction must begin in late summer or early fall of 2004. To achieve that goal we must work through the various permitting and approval processes as efficiently as possible. Xcel Energy is filing site permit applications and route permit applications with the Environmental Quality Board promptly after this filing. We will also be submitting an air quality permit application to the Pollution Control Agency.

We have briefed Commission staff concerning the pressing nature of the need for generating additions to ensure a reliable power supply and we very much appreciate their expression of willingness to give this matter their attention and to coordinate their efforts. In this proceeding we respectfully ask the Commission to do everything it can to move our proposal expeditiously through the process. Because the identified capacity need begins in 2005, Xcel Energy respectfully requests that consideration of this Application be expedited to the extent possible. See Minn. Statutes 216B.243, Subd. 5:

> *Within six months of the submission of an application, the commission shall approve or deny a certificate of need…*

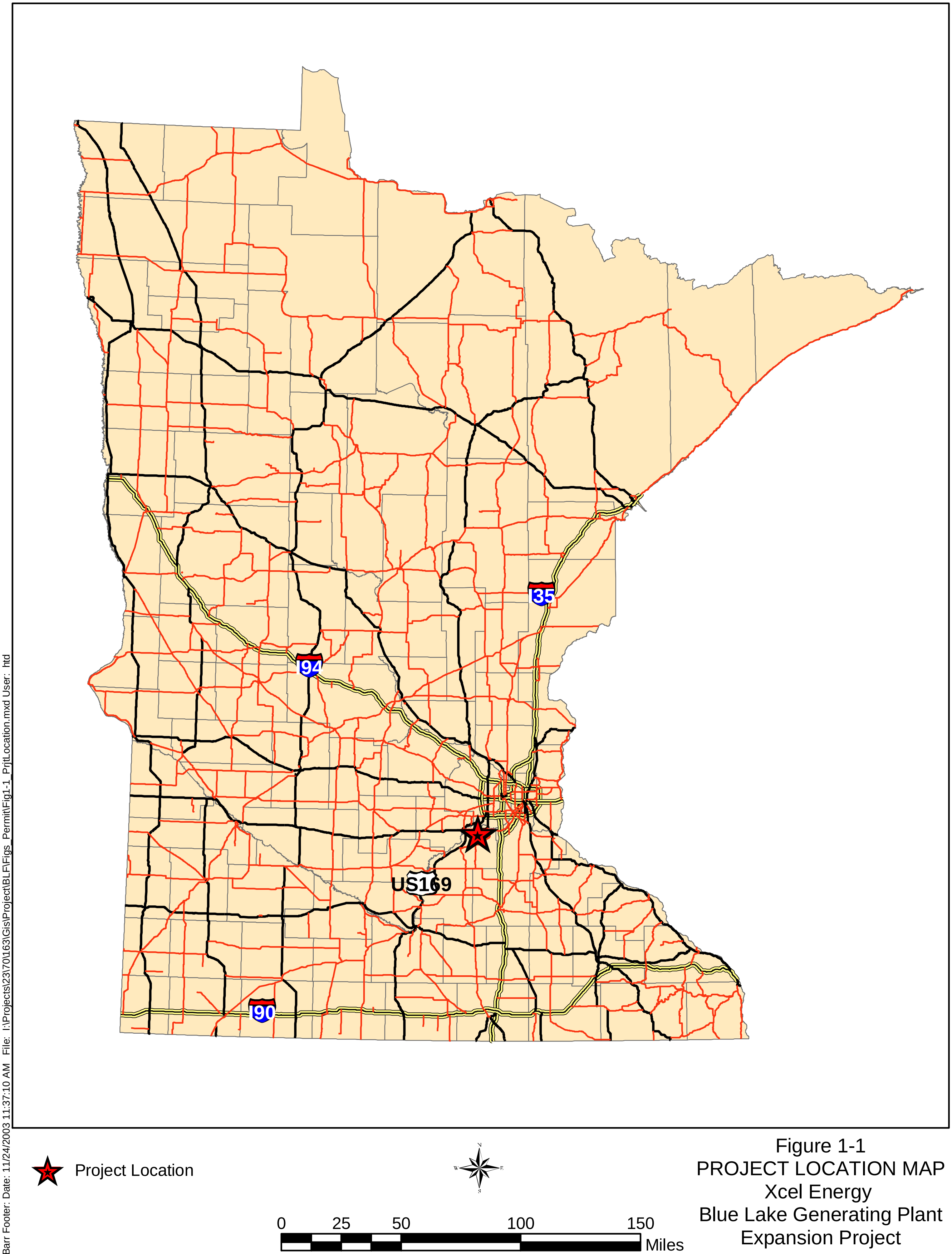
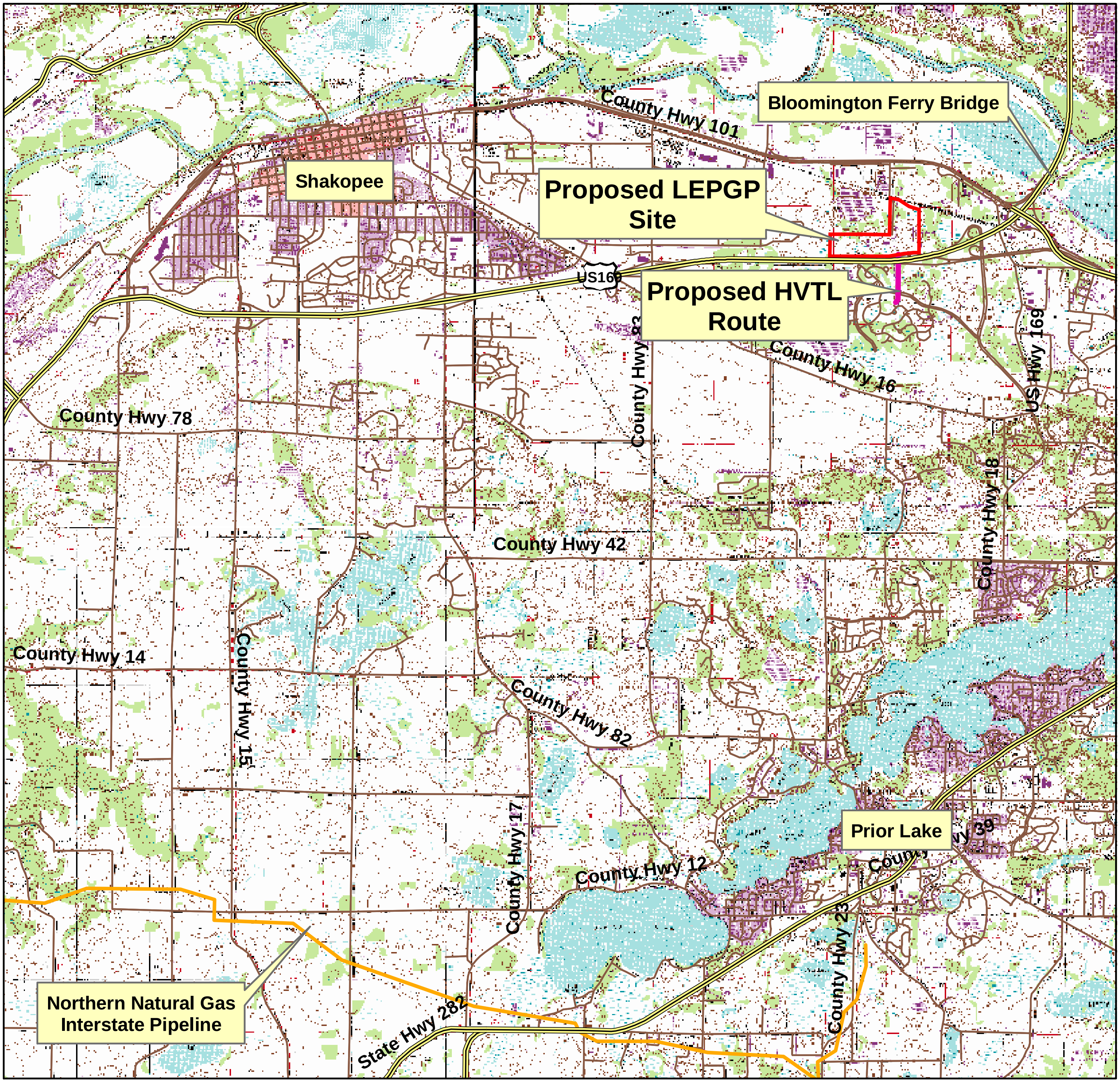


Figure 1-1
PROJECT LOCATION MAP
Xcel Energy
Blue Lake Generating Plant
Expansion Project



0 3,000 6,000
Feet

Figure 1-2
PROJECT VICINITY MAP
Xcel Energy
Blue Lake Generating Plant
Expansion Project

We are not asking the Commission to prejudge our proposal, but rather, to move it through the process quickly so that, whatever the outcome, the reliability of the power supply can be maintained in 2005.

One of the necessary steps in the review is for the Commission to determine whether the Application is complete (Minnesota Rules 7849.0200, Subp. 5). To assist the Commission in this review Xcel Energy has provided a detailed "completeness checklist" at the end of the Application Table of Contents that cross-references all of the Application content requirements. We hope this will facilitate review and resolution of this Application.

1.3 Project Satisfies Criteria

The Commission's statutory authority for granting certificates of need comes from Minn. Stat. § 216B.243, which generally requires Commission review and certification of any large energy facility. Pursuant to the authority granted in Minn. Stat. § 216B.243, subd. 1, the Commission has established criteria to assess the need for a Large Electric Generating Facility (LEGF) in Minnesota Rules 7849.0120.

"A. The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states…,

B. A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record…,

C. By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health…, [and]

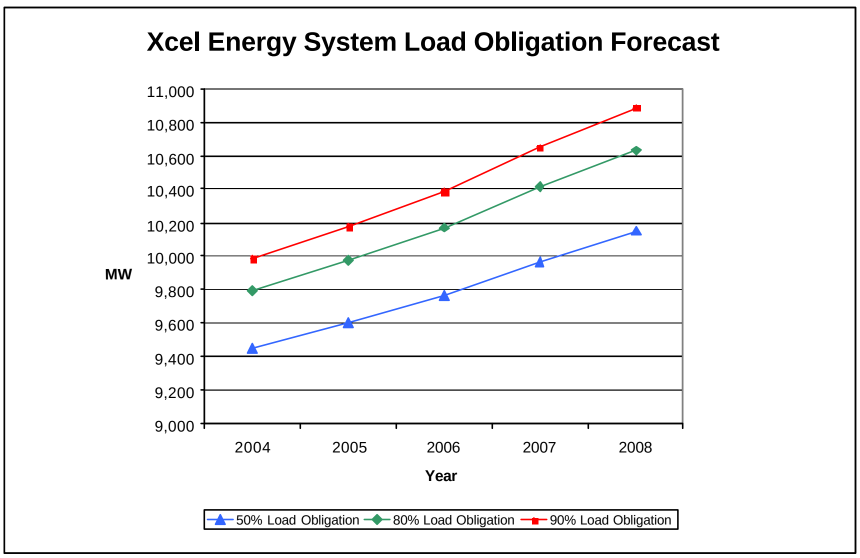
D. The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply *with relevant policies, rules, and regulations of other state and federal agencies and local governments…"*

Each of these criteria have been met in this Application.

1.3.1 More Adequate, Reliable, and Efficient Energy Supply

" The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply …,

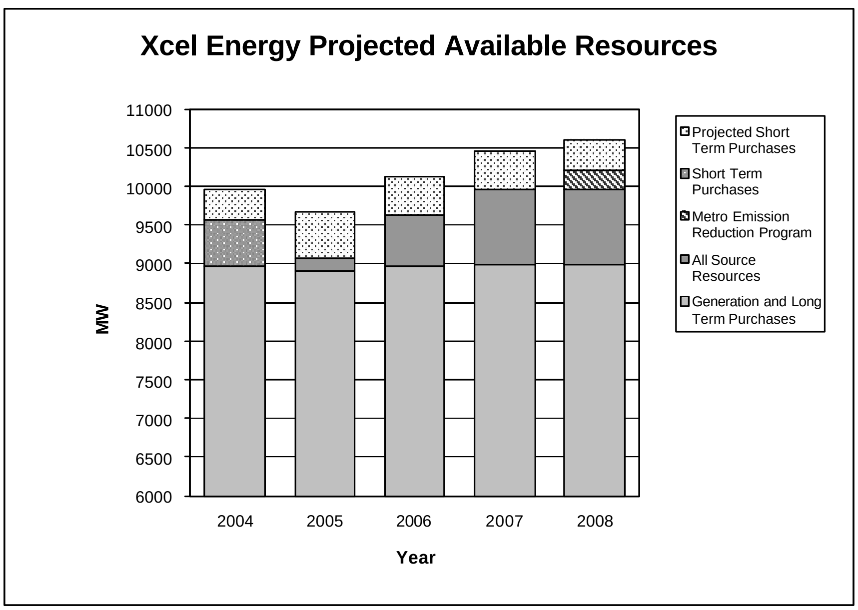
The Project's approximately 320 megawatts of production capacity is essential to the reliability of the region's electric energy supply. The figure below presents our forecast of the demand for electricity in coming years. The graph depicts the Xcel Energy System load obligation forecast, which is the anticipated annual peak demand for electricity after accounting for Commission approved conservation goals and production capacity reserve requirements to ensure system reliability.



In the 2000 Resource Plan Docket the Commission set goals for Xcel Energy's conservation and load management programs. Xcel Energy invests over $34 million annually to assist customers in their efforts to conserve and efficiently use electricity. Today we have arrangements with customers that allow us to interrupt service during peak periods of demand that reduce power consumption by over 800 megawatts. We are working toward and meeting the goals to increase conservation and load management established by the Commission.

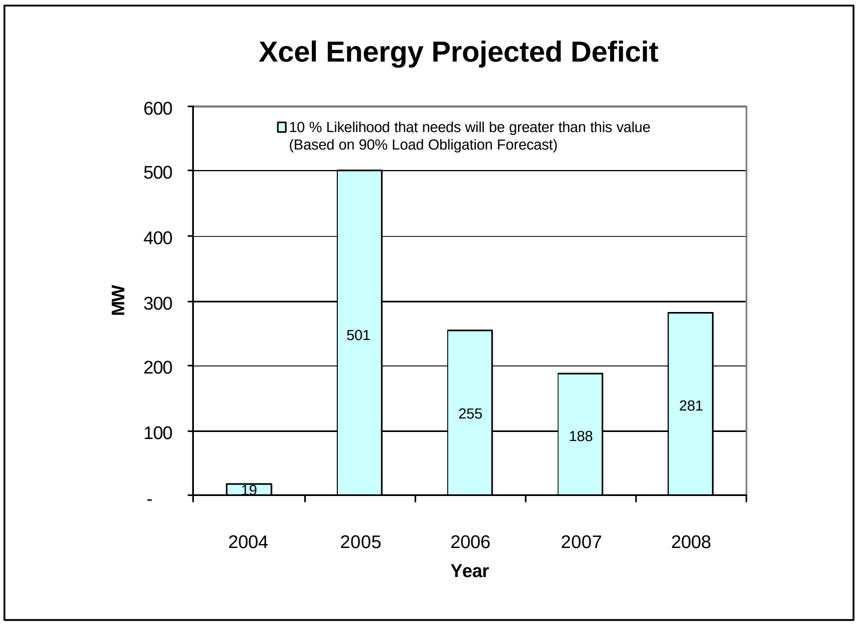
Electrical power at the utility scale cannot be stored. It must be produced at the same instant it is called upon by customers. Because of this unique circumstance utilities must have productions resources available so that power can continue to be delivered should any generator or transmission line fail. Working together, utilities have developed agreements to pool backup production capacity needed to ensure system reliability. In the upper Midwest, utilities must provide a 15% reserve margin to ensure system reliability. By coordinating reserve requirements the total amount of generating capacity each utility must maintain is minimized.

Xcel Energy meets the demand for electricity by producing electrical power at Xcel Energy's 22 power plants in the region, through long-term power purchase contracts with others in the region, and through shorter term power purchases. The figure below presents Xcel Energy's current projection of available production resource in coming years.



As described earlier and in more detail in Section 5, the production capacity estimates are lower than forecast in early 2003. They reflect changes, recently encountered, in the region's wholesale electric supply system primarily due to capacity limits of the transmission system. As the result of these recent changes Xcel Energy could experience a production capacity shortfall in upcoming years—as much as 500 MW in 2005—as illustrated in the figure below.

Xcel Energy is continuing to seek additional resources through the short term market. However, those efforts have also been impeded by the transmission limitations and even if those efforts are partially successful the need for additional generation in the 2005 timeframe is apparent. Without the addition of additional power production capacity in a location that is not susceptible to transmission limitations the reliability of the power supply to Xcel Energy's customers and surrounding utilities is at risk.



1.3.2 Best Alternative

" A more reasonable and prudent alternative to the proposed facility has not been demonstrated …,

The Project is the best alternative to meet the needs of Xcel Energy's customers.

The need for production capacity that has been identified will occur during periods of peak demand for electricity, primarily during hot days in the summer. The total number of hours these resources will be called on to operate will be small, however they must be able to respond readily when called upon. They will serve peaking duty.

The simple cycle technology is well-suited to meet the peaking objectives of the Project because of its relatively low capital cost; flexibility of operation, particularly the ability to be brought into operation quickly.

Simple cycle combustion turbine technology is well tested reliable technology at the utility scale. It is modular and relatively simple to install which allows it to be implemented in the short time available. Moreover, because of the small amount of time peaking facilities such as those proposed here operate (2-8 percent of the time), use of natural gas fuel is minimized. The air permit for this facility will limit operation to 8 percent of the hours, further reducing the risk of over reliance on natural gas fuel.

In Section 6 of our Application we systematically test a broad spectrum of alternatives to the proposed Project ranging from more conservation, to renewables-based generating alternatives, to other fossil fueled alternatives. Most of the alternatives cannot meet the projected need in the time available to do so. Others are more expensive than simple cycle gas fired combustion technology. The Project is occurring at a time when several combustion turbines are available on the secondary market. As the result, Project costs are substantially lower than they might otherwise be.

1.3.3 Benefits Society

"…the proposed facility, … will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health."

First and foremost the proposed Project will provide the electrical power production capacity required to reliably serve the needs of our customers. In so doing the State and region's economy can continue to grow, the role electricity plays in the protection of the environment can be reliably maintained, and essential health service can be delivered.

Simple cycle gas fired technology minimizes the potential for environmental effects associated with electrical power generation. Air emissions from a natural gas-fired simple cycle units are significantly lower than other fossil fuel alternatives. Water requirements for its operation are very small. The modular nature of the technology allows it to be added at existing plant sites thus minimizing land use impacts. Only a short new transmission line interconnection to the existing metropolitan Twin Cities transmission system is required to accommodate the increase in generating capacity at the Blue Lake Generating Plant site. Section 4 of this Application describes the environmental impacts of the Project in more detail.

Construction of the Project will require an estimated 90 to 120 construction workers over the one-year Project construction period. These high-skill, high-paying positions, including, pipefitters, iron workers, millwrights, carpenters, electricians and other trades, are estimated to add over $8 million of payroll into the regional economy. Operation of the new CTGs after the Project construction will require 2 to 3 full-time positions.

1.3.4 Consistent with Rules and Policies

"…the design, construction, or operation of the proposed facility, … will … comply with relevant policies, rules, and regulations …"

The Project is consistent with overall state energy policy and will comply with all applicable rules and regulations.

The Project serves the State energy policy goals as stated in the Minnesota Department of Commerce publication *Energy Policy & Conservation Report 2000* by:

- Improving the electrical system reliability for the long term,
- Building the most cost effective, least environmentally damaging resource,
- Being located to take advantage of existing capacity in the transmission infrastructure to ensure greater reliability of the system, and

- Providing a resource that will ensure affordable energy for all Minnesotans.

The Project will take advantage of existing infrastructure including site improvements and substation and transmission facilities. This use of existing transmission facilities is consistent with the State of Minnesota's commitment to non-proliferation of transmission corridors.[1]

The Project will meet or exceed the requirements of all applicable federal and state environmental laws and regulations.

1.4 Project Serves the Public Interest and Satisfies Requirements

The Commission should grant the requested certificate of need. As summarized above and described in detail below, the Project satisfies all four prongs of the Commission's criteria under Minn. R. 7849.0120. Moreover, this Project is in the public interest and satisfies all of the relevant statutory requirements. *See* Minn. Stat. § 216B.243, subd. 3 (showing required for construction) and Minn. Stat. § 2422, subd. 4 and § 216B.243, subd. 3a (preference for renewables).

The Project will provide a variety of benefits to the people of Minnesota and neighboring states and Xcel Energy's customers. The Project:

- Meets Xcel Energy's forecasted energy demand during peak consumption periods and its associated reserve capacity requirements. Minn. Stat. § 216B.243, subd. 3 (1);
- Provides a facility that is commercially proven at the several-hundred megawatt scale that can be available for the 2005 summer peak season. Minn. Stat. § 216B.243, subd. 3(2) and (3);
- Enhances the reliability of the bulk electric system by by ensuring Xcel Energy can meet its reserve capacity

[1] People for Environmental Enlightenment and Responsibility (PEER) v. Minnesota Environmental Quality Council, 266 NW2d 858 (Minn. 1978)

obligation. Minn. Stat. § 216B.243, subd. 3 (3) and (5);

- Minimizes environmental and community impacts by leveraging existing generation infrastructure and using efficient and environmentally-friendly technology. Minn. Stat. § 216B.243, subd. 3 (5);
- Enhances ratepayer value, reduces ratepayer risk by implementing the lowest cost feasible alternative and leveraging existing generation infrastructure, and provide economic benefit to the area community. Minn. Stat. § 216B.243, subd. 3 and subd. 3a; 216B.2422, subd. 4;
- Is the best alternative available to meet the identified need in light of all of the circumstances, is in the public interest and is consistent with the policies, rules and regulations of other governmental agencies. Minn. Stat. § 216B.243, subd. 3(6), 3(7) and subd. 3a; and
- No promotional activities gave rise to this Project, Minn. Stat. § 216B.243, subd. 3(4), and no combination of energy conservation, demand side management or renewable energy option will meet the identified capacity need in the time frame required. Minn. Stat. § 216B.243, subd. 3(2) and 3(8); Minn. Stat. § 2422, subd. 4 and 216B.243, subd. 3a.

2 General Information

2.1 Applicant: Xcel Energy

2.1.1 Address/SIC Code

Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500
SIC Code: 4911

2.1.2 Contact

Jim Alders
Manager, Regulatory Projects
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-6732

2.1.3 Description of Business and Service Area

Xcel Energy is a public utility under the laws of the state of Minnesota. The formal legal name of Xcel Energy is Northern States Power Company, a Minnesota corporation. Xcel Energy and its parent public utility holding company are headquartered in Minneapolis, Minnesota.

Xcel Energy has 1.5 million electricity customers in its upper Midwest service territory, shown in Figure 2-1, which includes parts of Minnesota, Wisconsin, Michigan, North Dakota and South Dakota.

Xcel Energy owns and operates 22 electric generation facilities serving this area using a variety of technologies and fuels including, coal, oil, natural gas, hydro, refuse derived fuel (RDF) and nuclear. Wind, landfill gas and additional hydropower are also included in Xcel Energy's portfolio through power purchase agreements.

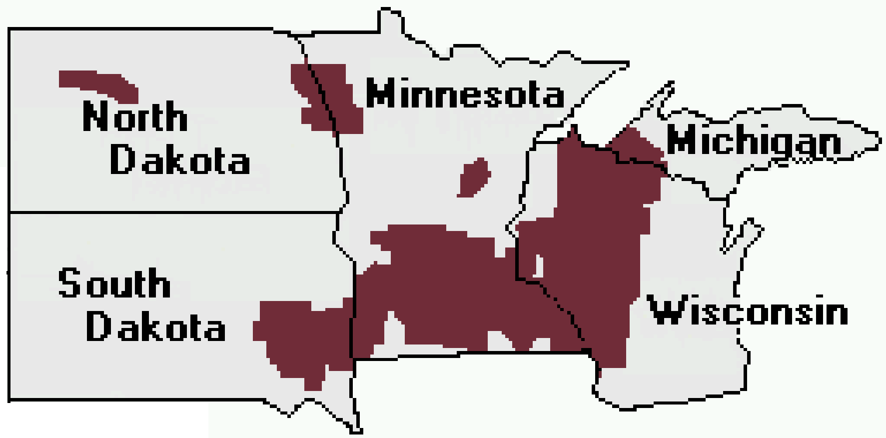


Figure 2-1
XCEL ENERGY UPPER MIDWEST SERVICE TERRITORY
Xcel Energy
Blue Lake Expansion Project

2.2 Related Filings and Permits

2.2.1 Information for Environmental Report

Minnesota Environmental Quality Board regulations (Minnesota Rules 4410.7000) specify that the environmental review required under Minnesota Statutes Chapter 116C for large electric power generating plants (LEPGP) shall consist of an environmental report at the Certificate of Need stage. Minnesota Rules 7849.0310 requires applicants for Certificates of Need to submit environmental information detailed throughout Chapter 7849. Xcel Energy has furnished such environmental information in this Application.

2.2.2 LEPGP Site Permit

Minnesota Statutes 116C.51-.69 requires that a Large Electric Power Generating Plant (LEPGP), power plants larger than 50 MW, obtain a Site Permit from the Environmental Quality Board. Xcel Energy expects to file a site permit application in promptly under the alternative permitting process described in Minnesota Rules 4400.2000 to 4400.2950.

2.2.3 HVTL Route Permit

Minnesota Statutes 116C.51-.69 requires that a High Voltage Transmission Line (HVTL), electric transmission lines with nominal voltage of 100 kV or more, obtain a Route Permit from the Environmental Quality Board. Xcel Energy expects to file a site permit application promptly under the alternative permitting process described in Minnesota Rules 4400.2000 to 4400.2950.

2.2.4 Gas Pipeline Route Permit

Xcel Energy will apply for a gas pipeline routing permit in accordance with the requirements of Minnesota Statutes 116I.015 and Minnesota Rules 4415 to construct a natural gas pipeline to furnish natural gas for the Project. Xcel Energy's natural gas supplier will apply for other necessary permits for the gas pipeline, including, if required for the pipeline construction:

- MPCA NPDES General Stormwater Permit for Construction Activity,
- MDNR License to Cross Public Lands and Waters,
- MDNR Wetland Replacement Plan Application, and
- U.S. Army Corps of Engineers Section 404 Wetland Permit.

2.2.5 Other Project Permits

2.2.5.1 Air Quality Permit

Xcel Energy will submit an air quality permit application to the Minnesota Pollution Control Agency.

2.2.5.2 Water Appropriations Permits

Xcel Energy will request an amendment to its existing groundwater appropriation permit (No. 731114) for the Plant to meet the water needs of the Plant resulting from the Project.

2.2.5.3 Wastewater Discharge Permit

Xcel Energy plans to dispose of Project wastewater at a POTW so its discharges would be covered under the POTW's NPDES discharge permit. Xcel Energy will comply with the requirements of the POTW for accepting Project wastewater.

2.2.5.4 NPDES Stormwater Program

The Project will disturb over one acre and therefore triggers the requirement to apply for coverage under the Minnesota Pollution Control Agency's (MPCA) NPDES Stormwater Permit Program for Construction Activities. Xcel Energy will require its contractor to apply for and comply with the construction storm water permit.

2.2.5.5 Other Permits

The Project may require permits, approvals or notifications under the following programs:

- Exemption to allow burning of natural gas for power production (DOE, 10 CFR 503)

- Road Crossing Permits (Mn/DOT, Minn. Rules Chpt. 8810)
- Miscellaneous State Building and Construction Permits and Inspections
- Miscellaneous Local Building and Construction Permits and Inspections.

3 Project Description

Xcel Energy proposes to add two simple cycle natural gas fueled combustion turbine generators to the Blue Lake Generating Plant in Shakopee, Minnesota. Each combustion turbine generator (CTG) has a nominal capacity of approximately 160 megawatts. As described in Section 5, the turbine additions are needed to meet peaking duty requirements during periods of time when electrical demand is highest. Without the addition of new peaking duty production resources by the summer of 2005, the reliability of our power supply could decline substantially.

3.1 Project Location

The Project is located within the Blue Lake Electric Generating Plant site. The site is located at 1200 70th Street South, in Shakopee, Minnesota 55379 and is approximately 15 miles southwest of Minneapolis (see Figure 1-2). The Plant is located in Township 115N, Range 22W, Section 11 in Scott County.

The Plant property covers about 127 acres south of the Minnesota River between MN Highway 101 to the north and US Highway 169 to the south. The area immediately to the north, west and east is industrial. US Highway 169 borders the site to the south. Across US 169 from the site is single-family and multiple unit residential development.

3.2 Project Overview

A simple cycle gas combustion turbine has a compressor to draw in and compress air; a combustor (or burner) to mix the compressed air with fuel and burn it to expand the mixture; and a turbine to extract power from the hot gas flow. Figure 3-1 is a schematic illustration of a simple cycle CTG power plant. The CTGs will be natural gas fired only.

Major components of the Project include two GE 7FA dry low NOx gas fired CTGs the generator voltage from 18KV to 115KV, which is then connected via a 115KV HV

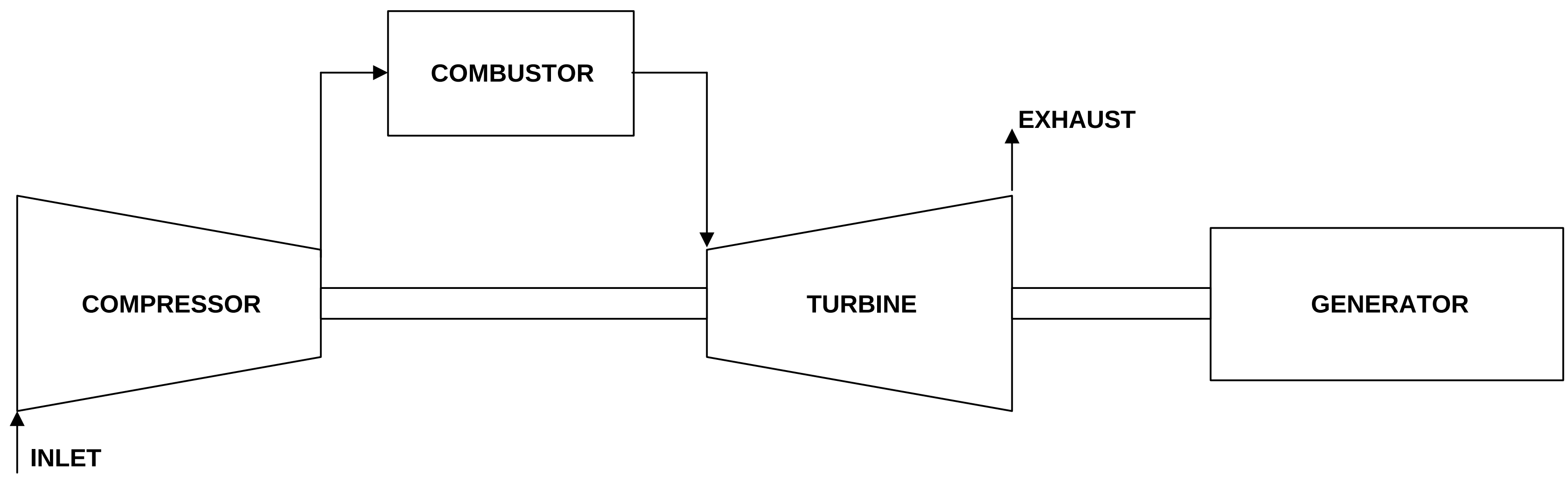


Figure 3-1
SIMPLE CYCLE SCHEMATIC
Xcel Energy
Blue Lake Generating Plant
Expansion Project

overhead line to the existing Blue Lake Substation. A new 230/115 kV transmission interconnection will be constructed from the substation approximately 1200 feet south to an existing 230 kV transmission line. A gas compressor station may also be constructed at the Plant to provide the gas pressures necessary for operation of the Project.

Existing Plant structures include an office building, turbine building and stacks, storage buildings, fuel tanks and transmission towers. The new CTGs will be placed between the existing turbine building and the existing fuel tanks, on an area that has been previously graded flat and covered with gravel. Figure 3-2 shows the major features at the Blue Lake Plant and the proposed layout of the new CTGs and associated facilities.

The existing turbine building and stacks are approximately 50 feet tall. The existing administration building, which includes the control room, will not change. The new turbine enclosures are expected to be a similar height to the existing CTGs' enclosure. The new CTG exhaust stacks will be between 50 and 75 feet tall.

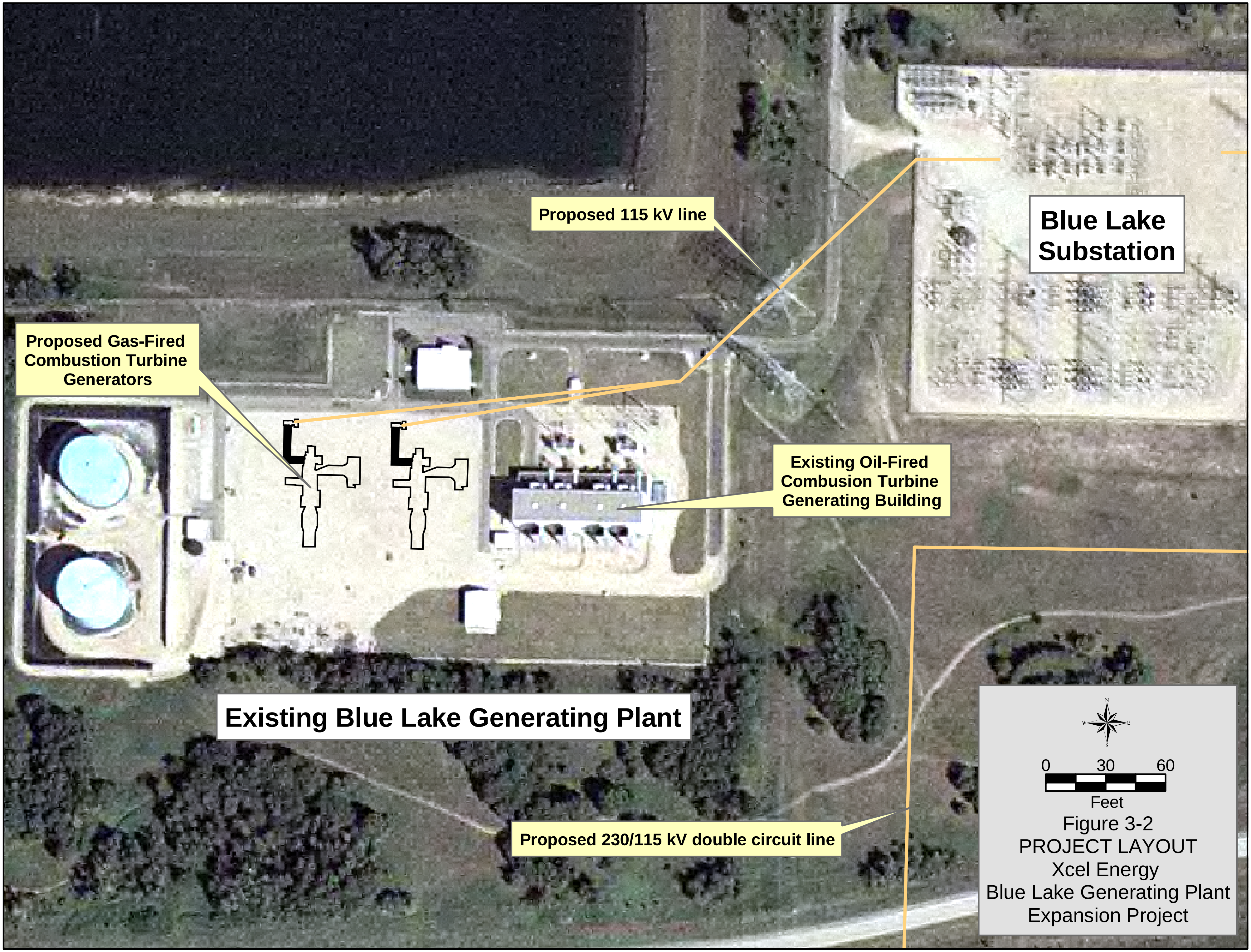
A service life of 30 years is assumed for comparing the Project to other alternatives. This is the minimum expected life of the CTGs and other major Project components given proper operation and maintenance over time.

3.3 Design Capacity

The maximum net output of the CTGs depends on ambient weather conditions (primarily temperature and humidity), as summarized below.

Condition	Temperature, Rel. Humidity	Capacity/CTG
ISO	59 degrees F, 60% Rel. Humidity	162 MW
Summer	90 degrees F, 60% Rel. Humidity	150 MW
Winter	-20 degrees F, 60% Rel. Humidity	185.5 MW

For purposes of this Application, if not specified, capacity will refer to International Standards Organization (ISO) conditions maximum net rated output. ISO conditions are the generation industry standard for


Proposed 115 kV line
Blue Lake Substation
Proposed Gas-Fired Combustion Turbine Generators
Existing Oil-Fired Combustion Turbine Generating Building
Existing Blue Lake Generating Plant
Proposed 230/115 kV double circuit line
N
W
E
S
0
30
60
Feet
Figure 3-2
PROJECT LAYOUT
Xcel Energy
Blue Lake Generating Plant
Expansion Project

describing turbine ouytput. Xcel Energy expects that the Project will

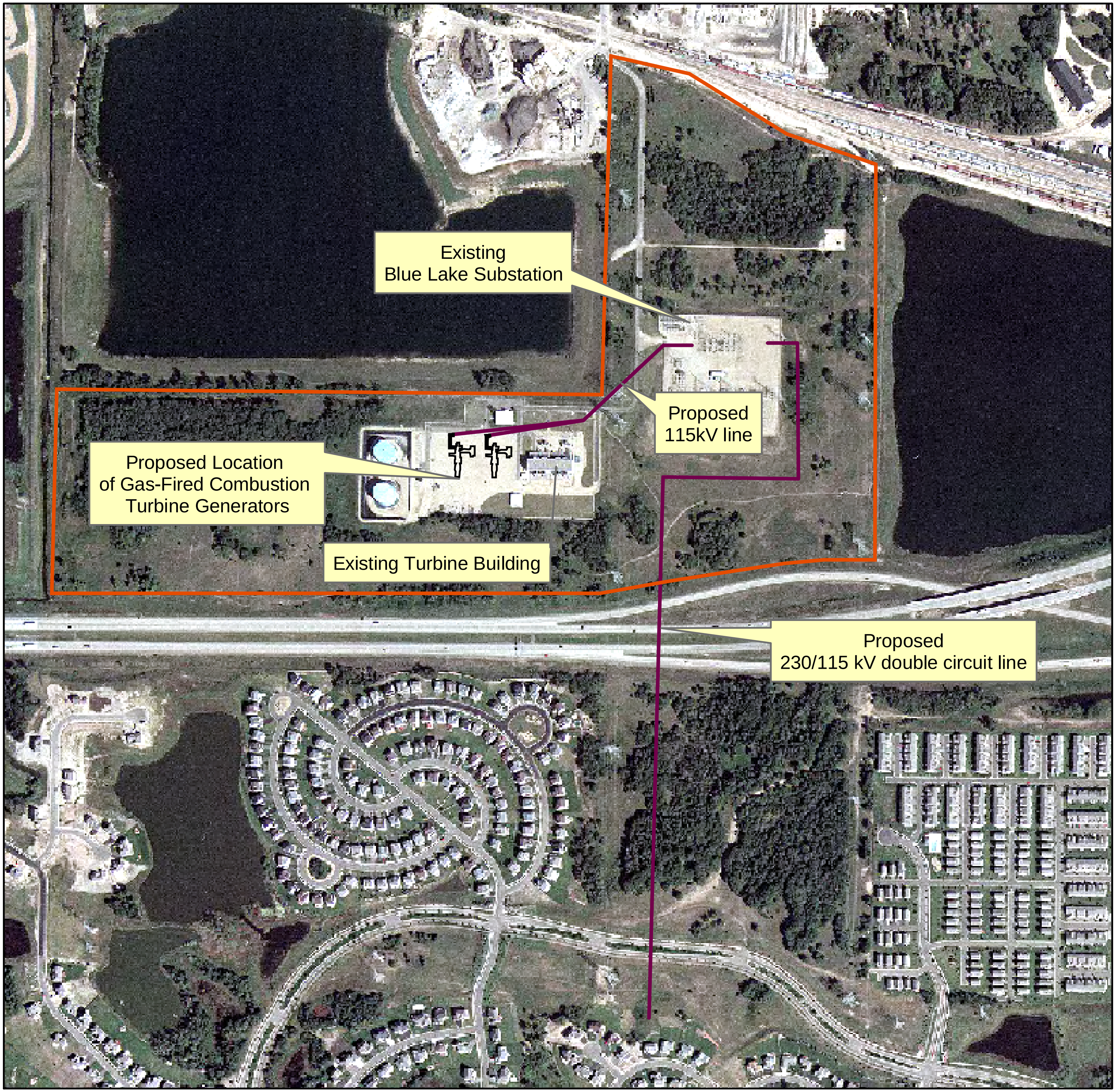
operate primarily during the summer to meet peak demand.

3.4 Infrastructure Requirements

The existing site is readily accessible via truck or rail. There is a rail yard one-half mile from the site with adequate facilities and space for heavy haul of the CTGs and generator step up transformers. It is expected that other balance of plant equipment will be delivered to the site via truck.

The Project will be supplied with high pressure natural gas via a new 16- to 20-inch diameter high pressure natural gas pipeline fed from the exiting Northern Natural Gas interstate pipeline running east-west approximately 10 miles south of the Project site.

The proposed Project electrical transmission interconnections are shown in Figure 3-3. The Project will be interconnected to Xcel Energy's existing Blue Lake Substation located immediately east of the Plant with a 115 kV transmission line. Minor modification of the substation will be required, including replacement and addition of various breakers, disconnects and conductors. A new 230/115 kV double circuit transmission line will be constructed from the substation approximately 1200 feet south to an existing 230 kV transmission line to provide an outlet for the Project. The existing 230 kV circuit connects McLeod and Black Dog Substations. That portion of the circuit between McLeod and Blue Lake will remain at 230 kV. That portion of the circuit between Blue Lake and Black Dog Substations will be operated at 115 kV. An existing 230 kV transformer at Black Dog will be moved to the Blue Lake Substation. The Blue Lake to Black Dog 115 kV circuit will be reconductored with higher capacity cable using existing structures for the most part.



LEPGP Site

Approximate alignment of new transmission

0 100 200

Feet

Figure 3-3
ELECTRIC TRANSMISSION INTERCONNECTIONS
Xcel Energy
Blue Lake Generating Plant
Expansion Project

3.5 Construction Schedule

Permits and regulatory approvals necessary for the start of construction must be obtained by the fall of 2004. In order to meet the anticipated need for additional production capacity by the summer of 2005. A turnkey construction contract will be awarded January 2004 and

engineering design will begin and continue through July 2004. Foundation work will begin as soon as possible and the turbines will be set on the foundations immediately upon receipt of required regulatory approvals. Electrical and gas interconnections are planned for completion by February 2005. Commissioning and start up will commence in March 2005 with the units operational late in the spring of 2005.

3.6 Operation

3.6.1 Anticipated Operating Procedures and Frequency

The Project will be integrated into Xcel Energy's remote dispatch control center. Xcel Energy will use the Project's capability during peak demand periods.

Each new CTG will be able to start up and be at full load within about 40 minutes of initiating the startup sequence. The second CTG must lag the first CTG in start up initiation by about 20 minutes because of shared startup equipment, and as a result the two CTGs can be at full combined load within one hour.

The new CTGs will be limited to a total of 1,339 operating hours per year combined, corresponding to an annual capacity factor of less than 8 percent, because of air permitting constraints (see Section 4.1.1). In general, we expect the new units to operate between a 2 and 8 percent annual capacity factor, depending on demand and other factors.

3.6.2 Project Operational Data

The operational data requirements outlined in Minnesota Rules 7849.0250 and 7849.0320 are presented in Table 3-1.

Table 3-1 Operational Information Summary

Rule Reference	Description	Project Data
General Data		
7849.0250, A(1)	Nominal generating capability (ISO Conditions: 59 degrees F and 60% relative humidity)	324 MW (2 CTGs at 162 MW each)
7849.0250, A(2)	Operating Cycle	Simple-cycle
7849.0250, A(2)	Anticipated annual capacity factor	Up to 8%
7849.0250, A(4)	Anticipated heat rate (efficiency) (ISO Conditions)	9,672 Btu (LHV)/kilowatt-hour (35%)
	Heat Rejected (through exhaust gas of each turbine at base load)	900 million Btu/hr (summer conditions) - 1,086 million Btu/hr (winter conditions)
Fuel Data		
7849.0320, C(1)	Fuel source	Natural gas via Northern Natural Gas Interstate Pipeline
7849.0320, C(2)	Fuel requirement Natural gas	 1.5 million SCF/hr/CTG (summer conditions) - 1.8 million SCF/hr/CTG (winter conditions)
7849.0320, C(3)	Heat Input	1448 million Btu/hr/CTG (summer conditions) -1778 million Btu/hr/CTG (winter conditions)
7849.0320, C(4)	Fuel Heat Value Natural gas	 1000 Btu/SCF (LHV)
7849.0320, C(5)	Fuel sulfur, ash and moisture content Natural gas	 Sulfur content: 5.5 mg/m^3 Ash content: None Moisture content: <80 mg/m^3
Water Use		
7849.0320, E(1)	Estimated maximum groundwater pumping rate	750 gpm (intermittent)
7849.0320, E(2), E(3)	Estimated annual groundwater appropriation (for two new CTGs)	1.0 million gallons/year or 3.1 acre-feet/year (at 8% capacity factor and assuming

Rule Reference	Description	Project Data
		evaporative cooling used for 20% of operating hours)

3.6.3 Maintenance Requirements

Maintenance activities for the Plant's CTGs and balance of plant equipment will be based on power industry practices and the equipment manufacturer's recommendations. The frequency of CTG maintenance activities consistent with base firing conditions will include the following inspections:

- Combustor (every 400 starts)
- Hot gas path (every 800 starts)
- Major (every 1200 starts)

3.7 Cost Evaluation

Project costs are presented in Table 3-2 on the following page. Xcel Energy has estimated Project costs based on recent direct experience and information from public sources. The analysis in Table 3-2 assumes a capacity factor of 8 percent for the Project (see Section 3.6.1). Comparison of Project costs with alternatives is discussed in Section 6.

Table 3-2 Project Cost Analysis

No.	Item	Units	Expansion Project	Comments
Input Assumptions				
1	Base Capacity	MW	324	ISO Conditions (162 MW each unit)
2	Cost Basis	Calendar Year	2003	Used for cost analysis only--actual in-service date expected to be Spring 2005
3	Service Life	Years	30	
4	Level Annual Revenue Requirement (LARR)	Percent	11.53%	This corresponds to a first year revenue requirement of approximately $16.4 million, of which approximately 3/4 will be paid by Minnesota customers of Xcel Energy. Estimated System annual revenue requirement associated with the Project, in 2003 dollars, is $0.000405 per kW-hour.
5a	Capacity Factor	Percent	8	Operating Time (hrs)/ 8760 (hrs/year)*100
5b	Annual Operating Time	Hours	669	Anticipated hours at nominal capacity
5c	Heat Input (LHV)	million Btu/hour	3134	Based on turbine manufacturer data (ISO conditions)
6	Construction Cost	2003 $/kW	300	2003 cost basis
7	Fixed O&M Costs	2003 $/kW-year	9.23	Source: Internal Xcel market information
8a	Fuel Costs	2003 $/million Btu	5.22	Source: Internal Xcel market information
8b	Non-fuel Variable O&M Costs	2003 $/kW-hour	0.0003	Source: Internal Xcel market information
Capacity (Annualized Fixed) Costs				
11	Total Plant Capital Cost	2003 $	97,200,000	Capacity (MW)*Construction Cost ($/kW)*1000(kW/MW)
12	Annual Capital Recovery	2003 $	11,207,160	LARR (percent)*Total Plant Capital Cost (2003 $)
13	Annual Fixed O&M	2003 $	2,990,520	Fixed O&M Costs($/kW-
14	Total Annual Fixed Costs	2003 $	14,197,680	Annual Capital Recovery (2003$) + Annual Fixed O&M (2003$)
15a	Project Capacity Cost	2003 $/kW	43.82	Total Annual Fixed Costs (2003 $)/Capacity (MW)/1000 (kW/MW)
15b		2003 $/kW-hour	0.066	Total Annual Fixed Costs (2003 $) / Capacity (MW) / 1000 (kW/MW) / Annual Operating Time (hours)
Energy (Variable) Costs				
18	Net Annual Generation	MW-hours	217,000	Capacity (MW)*Annual Operating Time (hours)
19	Annual Fuel Consumption	million Btu	2,097,000	Heat Input (million Btu/hour)*Annual Operating Time (hours)
20	Annual Fuel Cost	2003 $	10,946,000	Fuel Cost (2003 $/million Btu)*Annual Fuel Consumption (million Btu)
21	Annual Non-fuel Variable O&M Cost	2003 $	65,000	Non-fuel Variable O&M Costs (2003 $/kW-hour)*Capacity (MW)*1000 (kW/MW)*Annual operating Time (hours)
22	Total Project Variable Generation Cost	2003 $	11,011,000	Annual Fuel Cost (2003 $) + Annual Non-fuel Variable O&M Cost (2003 $)
23	Project Energy Cost	2003 $/kW-hour	0.051	Total Variable Generation Cost (2003 $) / Net Annual Generation (MW-hours) / 1000 (kW/MW)
27	**Total Cost**	**2003 $/kW-hour**	**0.116**	Total Capacity Cost (2003 $/kW-hour) + Total Energy Cost (2003 $/kW-hour)

4 Project Environmental Information

Simple cycle CTG technology operates with minimal impact to the environment. Flexibility of operation available with simple cycle technology also contributes to fewer impacts to the surrounding environment by allowing the Project to come on line quickly and operate only when necessary. We expect noise from the Project will result in no perceptible increase in noise levels for area residences. Another advantage of simple cycle technology is that it can operate without need for significant quantities of water and minimal generation of solid and liquid wastes.

4.1 Air Impacts

4.1.1 Air Emissions

Natural-gas fired combustion turbine technology is among the cleanest means of generating utility-scale electricity. Natural gas combustion generates significantly less particulate matter, sulfur dioxide, and toxic air emissions (including mercury) than oil or coal.

The primary constituent of concern resulting from combustion of natural gas in a CTG are nitrous oxides (NO_X). The Project will control NO_X emissions through use of Dry low-NO_x burners. Good combustion practices will also control emissions of fine particulates, carbon monoxide, and volatile organic compounds.

An air emission permit application will be submitted in early 2004. Because the Project will serve peaking duty in Xcel's system and thus operate a limited number of hours a year, we have elected to pursue air quality permits with a limitation, or cap, on the total number of hours the CTGs will be allowed to operate. The cap on operating hours will be determined based on permissible annual emission limits that ensure no significant air quality impacts. By taking this approach the air permitting process can be streamlined.

Table 4-1 presents the estimated air emissions from the Project. Estimated impacts to ambient air quality summarized in Table 4-2 are based on preliminary modeling using a U.S. Environmental Protection Agency (EPA) approved dispersion model (ISC3-PRIME). Modeling predicts that ambient air contributions from the facility both before and after the Project will be well below ambient air quality standards. The modeling protocol and major assumptions are presented in Appendix A. Comparison of air impacts of the Project to alternatives is discussed in Section 6.

Table 4-1 Estimated Project Air Emissions

General		
Pollutant	**Emission Factor**[1] at Rated Project Capacity (average ambient conditions, base load) (lbs/hour per CTG)	**Emissions** (tons/year @ 1,339 operating hours)
SO_2	5.5	3.7
NO_X	59	39.5
PM_{10}	9.0	6.0
CO	30	20
VOCs	2.8	1.9

Hazardous Air Pollutants (HAPS) (selected list from AP-42)			
Pollutant	**Emissions** (tons/year @ 1,339 operating hours)	**Pollutant**	**Emissions** (tons/year @ 1,339 operating hours)
1,3-Butadiene[2]	0.0005	Naphthalene (POM)	0.0014
Acetaldehyde	0.043	PAHs[3] (also POM)	0.0024
Acrolein	0.007	Propylene Oxide[2]	0.031
Benzene	0.013	Toluene	0.14
Ethylbenzene	0.036	Xylene	0.069
Formaldehyde	0.77		

[1]Emission factors for the general pollutants from manufacturer data.
[2]Emission factor is based on one-half the detection limits. Expected emissions are lower than the presented numbers.
[3]PAH is polycyclic aromatic hydrocarbon. POM is polycyclic organic matter.

Table 4-2 Estimated Maximum Contributions to Ambient Air Quality

Pollutant	Existing Plant Contribution to Ground-level Concentrations ($\mu g/m^3$)	Future Plant Contribution to Ground-level Concentrations ($\mu g/m^3$)	Ambient Standards ($\mu g/m^3$)
SO_2 (Annual)	0.010	0.010	80
SO_2 (24-hour)	63	63	365
SO_2 (3-hour)	138	138	1,300
SO_2 (1-hour)	174	174	1,300
NO_2 (Annual)	0.20	0.20	100
PM_{10} (Annual)	0.006	0.006	50
PM_{10} (24-hour)	19	19	150
CO (1-hour)	202	202	40,000
CO (8-hour)	84	84	10,000

Note: Modeling was conducted to demonstrate potential ambient air impacts associated with the Project. Modeling is not required by air quality regulations. Short-term (1 – 24 hour) concentrations based on hourly maximum emission rates. Annual modeled impacts from the existing plant based on 2000 actual emissions. Annual modeled impacts from the future plant based on 2000 actual emissions from the existing plant plus emissions based on 1,339 operating hours from each new CTG.

4.1.2 Fugitive Dust

Site preparation and construction activities will produce small amounts of fugitive dust from earth-moving and construction equipment. Fugitive emissions will be controlled to reduce their impact on area residents by watering or applying dust suppressants to exposed soil surfaces.

Fugitive dust emissions will not generated in any significant amounts during operation of the Plant.

4.2 Noise Impacts

Noise from the Project is not expected to have a significant impact. The Plant site is located in an industrial area where highway noise dominates the acoustic environment. The nearest residences are in the Classics at Waybridge subdivision located approximately 800 feet south of the Plant's fence line and approximately 1,000 feet south of the proposed CTG locations. Approximately 500 feet south of the Blue Lake Generating Plant and directly between the facility and the nearest residence is U.S. Highway 169, a well-traveled four-lane freeway. MN Highway 101, another well-traveled four-lane highway passes to the north of the Plant (see Figure 1-2).

We do not expect construction activity to be heard above the ambient traffic noise of U.S. Highway 169 and MN Highway 101. Construction of the plant does not require any equipment or operations that are out of the ordinary and construction will take place during the day.

Design of the CTGs will include noise control measures. Given the high background noise levels in the area, the distance of the CTGs from the nearest residential receptors and the noise control technology available, operation of the CTGs is not expected to result in perceptible increases in area noise levels.

4.3 Water Needs

An advantage of simple cycle technology is that it can operate without need for significant quantities of water. It is estimated that over 80 percent of the time the Project CTGs operate, no water will be used. Up to about 20 percent of the time, it is anticipated evaporative cooling will be used to cool the inlet air of the CTGs. Inlet air cooling using evaporative cooling enhances operational efficiency of the units during the warmest days of the year. Evaporative cooling increases the humidity, which results in cooling of the air entering the combustion turbine. The evaporative cooling process consumes a small amount of water, but increases output about 5 to 10 percent depending on the relative humidity during hot summer day operation.

The expanded Plant will also need water for fire protection. The Plant is equipped with its own complete fire protection system designed in accordance with National Fire Protection Association (NFPA) requirements. The Plant fire protection system will be upgraded as necessary. Additionally, the new CTGs will be equipped with a carbon dioxide fire protection system. The City of Shakopee Fire Department will be utilized for emergency situations.

The Project water needs can be met with the two existing on-site wells. No connection to a public water supply will be required. The estimated 1 million gallons of groundwater that may be appropriated annually to enhance the CTGs' operating efficiency during hot periods is insignificant compared to other area historical groundwater appropriations. It is expected that we will request an amendment to one of the wells' existing groundwater appropriation permit (No. 731114) for the Plant to address the water appropriation needs of the Project.

4.4 Waste Generation

Table 4-3 summarizes information on the solid and liquid wastes generated by the Project. The most significant waste streams from the Project will be wastewater resulting from the of treatment process for groundwater used for evaporative cooling (see Section 4.3). The wastewater will be similar in makeup to the groundwater and will be a relatively small volume. Other solid and liquid wastes will stem from routine maintenance activities.

All waste management activities will be conducted in accordance with applicable rules and regulations. Wastewater will be discharged by trucking to a regional POTW. At maximum allowed capacity factor (8 percent) and assumed frequency of evaporative cooling, the wastewater generated by the Project operation would require about 100 truckloads annually. Site domestic wastewater will continue to be discharged to the existing on-site drain field.

Table 4-3 Solid and Liquid Wastes

Waste	Phase	Description	Generation Rate	Disposition Method
Evaporative Cooler Blowdown	Liquid	Water containing dissolved solids present in the raw water source except at a greater concentration.	56 gpm (max.) <0.4 mgy	On-site storage and truck to POTW
Pressure Filter Blowdown	Liquid	Water containing dissolved solids present in the raw water source except at a greater concentration.	200 gpm (max.) <0.05 mgy	On-site storage and truck to POTW

Waste	Phase	Description	Generation Rate	Disposition Method
RO Reject Water	Liquid	Water containing dissolved solids present in the raw water source except at a greater concentration.	10 gpm (max.) <0.14 mgy	On-site storage and truck to POTW
Service Water	Liquid	Equipment wash water.	similar to present except during construction	On-site storage and truck to POTW
Sanitary Wastewater	Liquid	Domestic wastewater.	5000 gpy	No new fixtures; existing drainfield
Oil/Grease	Solid	Lubricants, hydraulic fluid, etc.	<20 barrels/yr	Manage used oil with a contract firm
Maintenance Materials	Solid	Oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, cleaning solvents.	<2 tons/yr	Dispose of properly as specially regulated, solid or hazardous waste and/or recycle as feasible and allowable

4.5 Pollutant Monitoring

Anticipated environmental monitoring that will be associated with the operation of the Project is limited to air quality monitoring. Air emissions monitoring will be completed in accordance with the air quality permit that will be issued by the MPCA.

4.6 Secondary Effects

4.6.1 Storm Water

Plant surface water runoff will continue to discharge to the south of the Plant to an existing ditch along the north side of U.S. Highway 169. Drainage patterns along the electric and gas interconnection corridors will not be significantly altered.

4.6.2 Traffic and Transportation Infrastructure

During construction of the Project, there will be a minor increase in traffic on 70th Street South in Shakopee, the single route into the Plant. Up to 120 additional construction personnel are expected on site during the peak of construction activities.

Operation of the Project will result in no significant increased traffic from current traffic levels. Up to about 100 tanker truck trips will be added annually to transport Project wastewater (see 3.1.4).

The existing roads and nearby rail yard will meet the Project access needs during construction and future operations. No railroad and only minor temporary road upgrades are necessary for the Project.

4.6.3 Labor Requirements

An estimated 90 to 120 union construction jobs will be created over the 12-month construction period, adding an estimated $8 million of payroll into the economy. An additional two or three new permanent jobs are expected to be created in the region.

4.6.4 Effects on Agricultural Land

No agricultural land will be used for the Project. The Project will be entirely on land already used for electric power production.

A portion of the new gas pipeline is expected to be constructed on agricultural land we expect the line will be placed in or adjacent to existing highway or utility rights–of–way to the extent practicable to minimize agricultural impacts. In areas where private easements are required, those easements will not take any land out of agricultural production.

Proper construction methods and restoration procedures will be followed to mitigate the impacts to land use.

4.6.5 Relocations

No relocations of people will be necessary to construct the Project—the Project will be entirely on land already used for electric power production. The new natural gas pipeline is expected to be placed in existing highway, utility rights–of–way or private easements and will not require relocations.

5 Denial Would Adversely Effect Adequacy, Reliability and Efficiency of Energy Supply System

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minnesota Rules 7849.0120). This section addresses the first criterion (Part A) that "the probable result of denial would be an adverse affect on the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states."

Xcel Energy's System is one of the primary systems serving Minnesota and neighboring states and Xcel Energy's System needs additional electric generating capacity to meet Xcel Energy's customers' electricity demands. The Project will result in a more adequate, reliable and efficient energy supply to Xcel Energy's customers and to the people of Minnesota and neighboring States by providing 324 MW[2] of peaking capacity. Denying approval of the Certificate of Need would increase the probability of inadequate regional generation capability and a reduction in the reliability of Xcel Energy's System and the regional electrical supply system.

5.1 Xcel Energy Forecasts Increasing Demand for Electrical Power

5.1.1 Current Peak Demand Forecast

Xcel Energy's most recent forecast of peak demand for electrical power from customers in its five state upper Midwest system is shown in Figure 5-1. Consistent with previous forecasts presented in Resource Plan proceedings we anticipate that the demand for electrical power will continue to grow at an average rate of

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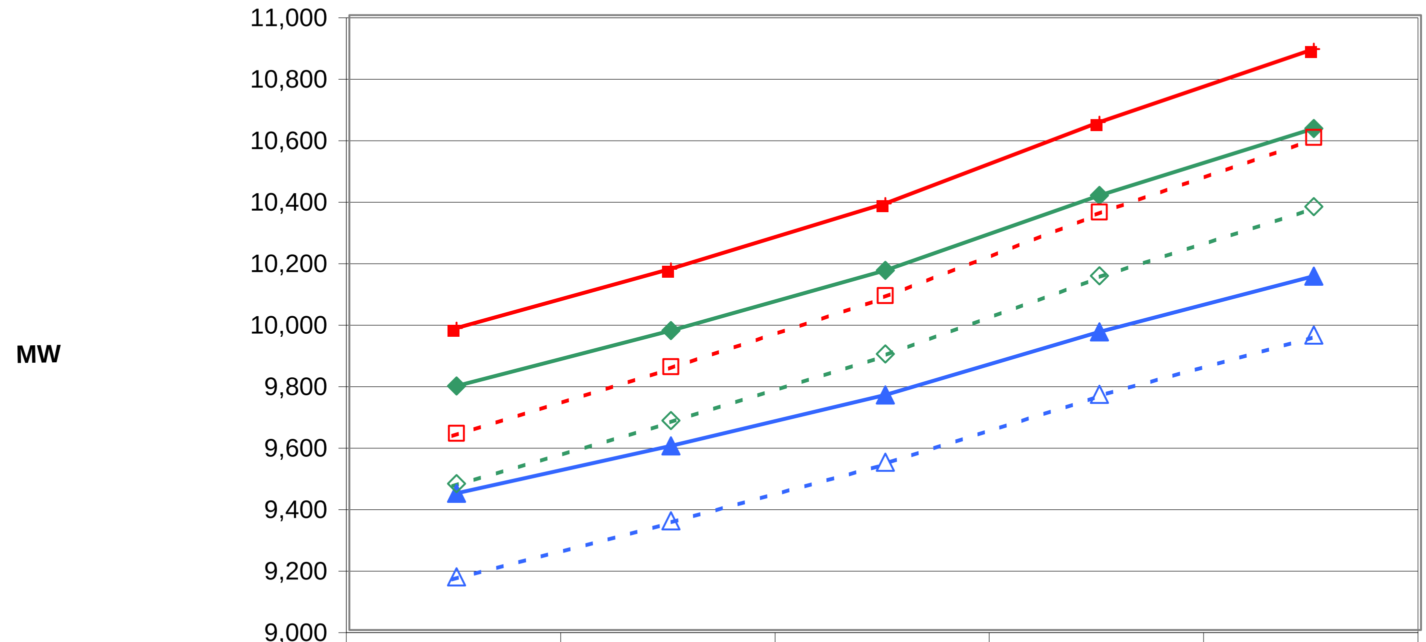
[2] ISO conditions rating.



	2004	2005	2006	2007	2008
50% Load Obligation *	9445	9599	9765	9970	10151
80% Load Obligation *	9794	9974	10170	10413	10631
90% Load Obligation *	9982	10175	10387	10652	10890
50% Peak Demand Forecast	9173	9355	9546	9766	9960
80% Peak Demand Forecast	9476	9681	9898	10152	10377
90% Peak Demand Forecast	9640	9856	10087	10359	10602

Year

* "Load Obligation" includes Load Management, Demand Side Management, and Reserve Capacity Obligation.

Figure 5-1
LOAD OBLIGATION FORECAST, SUMMER PEAK
Fall 2003 Forecast
Xcel Energy
Blue Lake Generating Plant
Expansion Project

2.6 percent per year or an average of an additional 240 MW each year.

The methodology used to develop the forecast demand and other forecast details required by Minnesota Rules 7849.0270 are provided in Appendix B.

As with any forecast, the relationship of the actual peak demand for electricity in a future year cannot be known with certainty. However, using statistical techniques, predictions can be made of the likelihood that peak demand will exceed various levels. The lowest dashed line in Figure 5-1 illustrate the peak demand level that is likely to be exceeded 50% of the time, the second dashed line represents the peak demand level that is likely to be exceeded 20% of the time and the highest dashed line represents the peak demand level that is likely to be exceeded 10% of the time.

In order to determine the level of generating resources necessary to meet peak electrical demand some adjustments to the forecast need to be made. The three solid lines in Figure 5-1 show total resource requirements at the three probabilities of being exceeded, referred to as load obligation, based on the forecast of peak electrical demand after the adjustments described below.

5.1.2 Demand Forecast Relies on Continued Aggressive Demand-Side Management

Xcel Energy has not engaged in promotional activities leading to the forecasted demand. To the contrary, the forecast information presented in this section takes into account the peak demand that can be avoided through our conservation and load management programs. Xcel Energy has in place over 800 megawatts of load management opportunities. The load obligation lines in Figure 5-1 reflect those load management capabilities.

Xcel Energy's current goals for conservation and load management result from an extensive examination that culminated in Commission approved demand side management goals. Xcel Energy is committed to the DSM goals as ordered by the Commission in the 2000 Resource Planning process. Xcel Energy's demand-side management goals are among the most aggressive utility programs in the United States.

It should be noted however that Xcel Energy has been experiencing some difficulty in maintaining it's customer base for it's load management programs. New customers are being signed up for these programs, but we have been seeing an increase in the dropout rate of current customers. We are committed to achieving the conservation and load management goals established in Resource Planning and have incorporated them in our forecast adjustments however there appears to be an increasing risk that our efforts may fall short. More detail on Xcel Energy's conservation and load management programs is presented in Appendix C.

5.1.3 Demand Forecast includes MAPP Reserve Capacity Obligation

Xcel Energy is also obligated as a member of the Mid-Continent Area Power Pool ("MAPP") to provide generating resources 15 percent in excess of its peak electrical demand so that adequate back up resources are available to all MAPP members in the event of critical equipment failures on the regional system. In this way upper Midwest Power Suppliers ensure the reliability of service to their customers. By pooling resources total production capacity can actually be reduced. Without the 15% reserve commitment from all power suppliers each company would have to provide a higher level of back up resources to ensure the reliability of its own system. Figure 5-1 reflect the 15 percent reserve capacity obligation, calculated after conservation and load management forecasts are applied.

The 15 percent reserve margin requirement is significant and must be complied with. Under MAPP's rules failing to meet the reserve margin requirement could result in significant penalties. MAPP's rules determine compliance and assess penalties on an after-the-fact basis, thereby making it very important that utilities accurately plan to have sufficient generation to meet the reserve margin requirement even in extreme weather or load conditions. Xcel Energy has never been assessed MAPP reserve margin penalties and the Project is in part intended to reduce the risk of reserve margin penalties in the near term.

5.2 Xcel Energy is Finding Fewer Available Resources

Xcel Energy meets the demand for electricity with a combination of Company-owned and operated generating facilities, long-term power purchases from other suppliers and short-term power purchases. In order to ensure that the actual demand and associated MAPP capacity reserve requirement can be met, Xcel Energy has traditionally made long-term purchases and generation capacity additions to meet a median (50^{th} percentile) demand forecast and then has augmented those resources with short term seasonal purchases to cover to the 80^{th} to 90^{th} percentile forecast. In that way, the risk that demand will exceed available resources is minimized in a cost effective manner.

Xcel Energy's most recent forecast of available resources for years 2004 through 2008, prepared in Fall 2003, is illustrated in Figure 5-2. The graph shows anticipated available resources categorized into owned generation plus long-term purchases, short-term purchases (both committed and projected), anticipated all-source solicitation process resources and the additional capacity projected to be available as a result of implementation of the Metro Emissions Reduction Project (MERP).

Xcel Energy's own generating capacity for its upper Midwest service territory customers is provided by its 22 major generating plants in Minnesota, Wisconsin and South Dakota. The energy sources for these plants are diverse and consist of coal, natural gas, nuclear fuel, water, oil and refuse. Significant additional fossil, hydro and renewable resources are used through long term power purchase contracts.

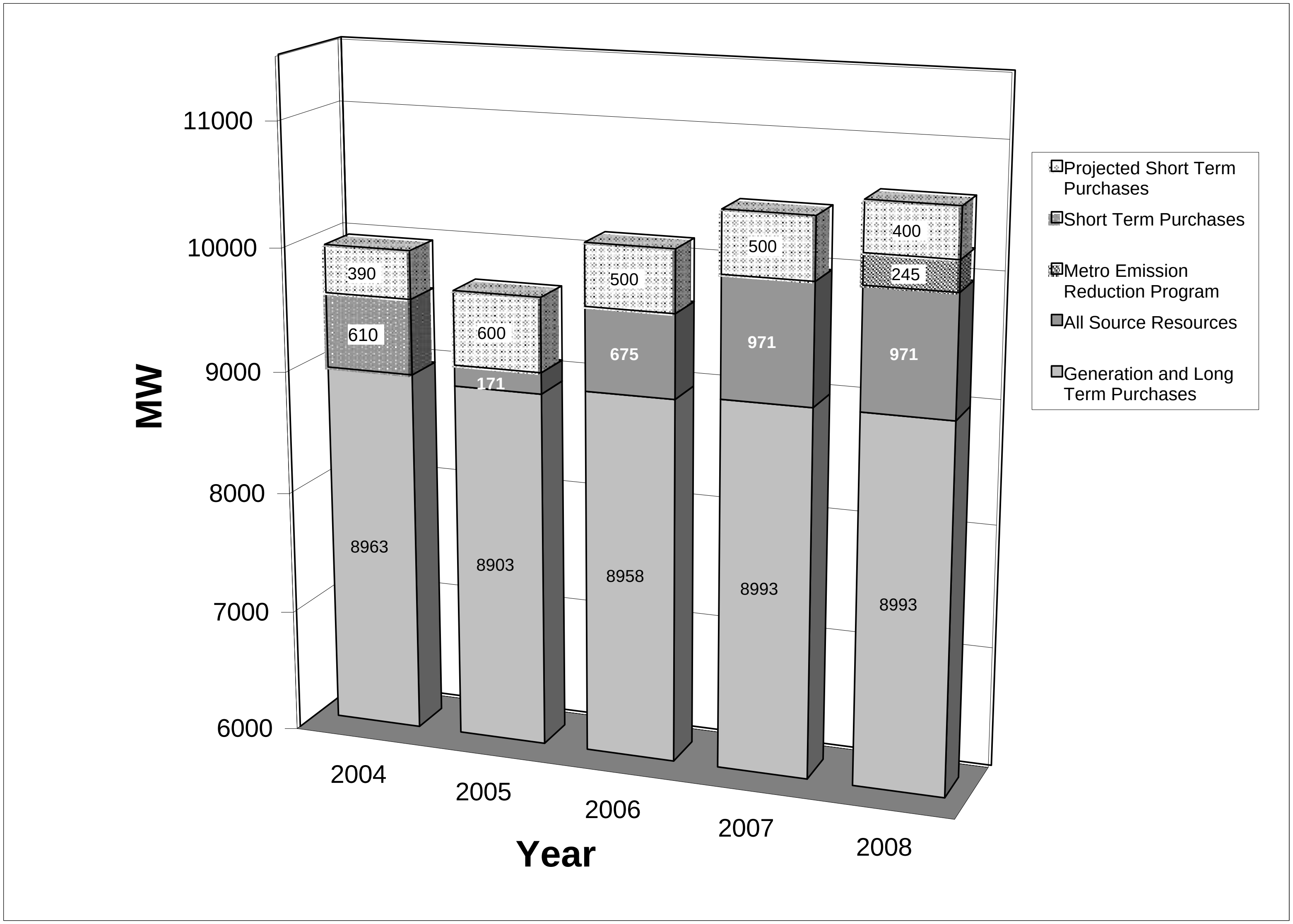


Figure 5-2
AVAILABLE RESOURCES
Fall 2003 Forecast
Xcel Energy
Blue Lake Generating Plant
Expansion Project

5.2.1 Short-term Purchase Options Decline

5.2.1.1 Xcel Energy Reduces Projections of Available Short-term Purchases

Recently, Xcel Energy encountered conditions in the regional market that lead it to conclude that it can no longer rely on the same level of short-term power purchases as in the past. This trend was identified in past resource plan filings but is occurring sooner than anticipated.

In years 2000 through 2003, Xcel Energy planned for and successfully secured 800 to 1100 megawatts of short-term power purchases along with the required firm transmission rights to deliver the contracted electricity to be delivered during the summer peak demand season. For its 2002 Resource Plan, Xcel Energy anticipated similar levels of short-term power purchases would be available for the years 2004 and 2005. However, because of concern about increasing demands on the transmission system and changes in the administration of the transmission system, the 2002 Resource Plan conservatively included an expectation of reduced availability of short-term power purchases starting with a reduction to 700 megawatts in 2006.

While the generation resources appear to be available in the region, it has become apparent that transmission capacity is no longer available to deliver that power from other systems to the Xcel Energy system. Accordingly, Xcel Energy has reduced its estimates of available short-term power that can be successfully delivered to the Xcel Energy system in future years. In 2005, short-term purchases are projected to be approximately 600 MW, about 300 MW lower than assumed previously. Available short-term purchase forecasts in future years are even lower: 500 MW in 2006 and 2007, and 400 MW in 2008 (see Figure 5-2).

5.2.1.2 Xcel Energy's Recent Short-term Market Experience

Over the past five years, approximately 400 to 500 megawatts of Xcel Energy's short-term purchases were made from utilities to the south of the Xcel Energy

System. Excess generation resources and transmission availability from the south had been sufficient to make these purchases an excellent source of economic capacity for Xcel Energy's System. Entering 2003, Xcel Energy believed that this situation would not change in the near term. Therefore, in early 2003, when Xcel Energy began its short-term purchase planning for 2004 and 2005, it continued to assume that the resources originating from utilities to the south would be available. As early as November of 2002, Xcel Energy submitted requests for transmission service to the Midwest Independent System Operator power to be delivered during the 2003 summer season. MISO notified Xcel Energy these requests would require system impact studies.

To ensure adequate capacity coverage for 2003, Xcel Energy requested monthly firm transmission while MISO studied the annual request. The principal difference between monthly and annual firm transmission service is that annual transmission reservations establish a transmission access right that can be preserved from year to year or rolled over. MISO authorized the monthly transmission at the same time that it was studying the annual request in more detail.

However, during the summer of 2003, Xcel Energy began experiencing refusals of other monthly transmission requests to facilitate day-to-day power transactions from the south. While these monthly transmission reservations did not impact the production capacity purchases for 2003, they did restrict economical electric energy purchases, an indication that transmission availability was tightening sooner than anticipated.

On September 4, 2003, Xcel Energy received the results of the system impact study from MISO for the annual transmission request submitted in November of 2002. The study identified numerous constraints that would limit Xcel Energy's ability to acquire firm annual transmission access from the south. Among others, MISO identified that transfers from the south were constrained by the Quad Cities limitation on the Mid-American system, part of the transmission network at the Iowa Illinois border. Xcel Energy then authorized MISO to conduct a Facility Study to identify the transmission improvements necessary to overcome the constraints.

MISO is currently working on this study and Xcel Energy expects the results in the spring of 2004.

Additionally, in early October 2003, the earliest time allowed by MISO procedures, Xcel Energy made new monthly firm transmission requests for power purchases from the south for the summer season of 2004. MISO immediately denied those requests. Xcel Energy expects they will receive similar results for 2005.

Based on these transmission access developments, Xcel Energy concludes that we cannot depend on short-term power purchases to the same degree as in the past. To complicate matters further, the North American power system experienced its largest blackout ever on August 14, 2003. Xcel Energy is concerned that the transmission system will be more conservatively administered until significant improvements are made and thus power purchases from other systems may decline further.

FERC and MISO procedures and tariffs provide for the rollover of certain transmission rights from one year to the next. While Xcel Energy is limited in the amount of power that can be delivered from the south, Xcel Energy continues to believe we can secure enough power for the 2004 summer season from other sources, using rollover transmission rights and unconstrained transmission paths, to cover peak demand and reserve obligations to the 85^{th} to 90^{th} percentile forecast probability.

However, because of the significant uncertainty in the regional transmission capacity picture in 2005 and beyond, Xcel Energy believes it is no longer prudent to rely as heavily on short-term seasonal power purchases from distant utilities to meet our customer's needs and reliability obligations. Xcel Energy will continue to pursue purchases as they are available but can no longer count on their availability for the foreseeable future.

5.2.2 All-Source Long-Term Resources are Limited and Delayed

5.2.2.1 Xcel Energy Reduces Projections of Available All-Source Long-term Purchases

Xcel Energy anticipated that approximately 800 to 1,000 MW of capacity would be available through the 2001 All-Source bid process. We are continuing to pursue adding capacity through the All-Source bid process but the complexities and time consuming nature of bid evaluation and power purchase agreement negotiations, along with serious constraints on the transmission system that have been encountered, make it unlikely that most of the needed capacity will be secured by 2005.

Xcel Energy's most recent forecast of available resources illustrated in Figure 5-2 show the assumed All-Source Resources that will be available 2005 through 2008. Some of the same transmission constraint issues encountered in Xcel Energy's efforts to secure short-term seasonal power supplies have presented challenges in Xcel Energy's 2001 All-Source long-term resource acquisition program. Xcel Energy continues to believe we will successfully secure over 800 megawatts of production capacity as the result of the program, however, due to "work arounds" necessary to address transmission constraints; we have reduced our estimate of how much of that capacity will be available in 2005 by 200 megawatts.

5.2.2.2 Xcel Energy's Recent All-Source Process Experience

In June 2003, Xcel Energy announced its selection of 7 finalists in the 2001 All-Source, long term, resource acquisition program. Those selections were:

- a 100 MW purchase from the Minnesota Power system,
- a 250 MW purchase from Reliant from an existing plant in Illinois,
- a 240 MW purchase from Calpine from a gas combined cycle plant to be built in Wisconsin,

- a 155 MW purchase from TransCanada from a gas combustion turbine unit to be built near Hutchinson, Minnesota, and
- three power purchases totaling 450 MW of nameplate capacity from wind farms on Buffalo Ridge and in south-central Minnesota

Shortly after the announcement of the finalists, preparations for contract negotiation and preliminary discussions began. Preparations included contacting bidders, incorporating project details into the model purchased power agreement, and continued due diligence on project development. While all of the finalist bidders initially identified in their proposals 2005 in service dates, we anticipated it would be difficult to complete the as yet undeveloped projects by 2005. However we did expect to complete negotiations and make purchases from at least the Minnesota Power proposal and the Reliant Illinois proposal, both existing generation, beginning in 2005. On August 6, 2003, Minnesota Power informed Xcel Energy that they were completing negotiations with another utility to dedicate the capacity and energy that was the subject of their All-Source proposal to Xcel Energy. Xcel Energy and Minnesota Power spent some time discussing if the All-Source bid could be completed or a substitute arrangement could still be made. On August 25, Minnesota Power notified Xcel Energy that it had executed the long-term transaction with another utility and formally withdrew their All-Source bid.

During preparations for negotiations with two of the other bidders, it became apparent that the Quad Cities limitation, which prevented MISO from approving the short-term transmission requests from the resources to the south, might also prevent long-term purchases from the Reliant facility and from the Calpine project in Wisconsin. Xcel Energy had expected that mitigation efforts and the use of certain transmission paths would enable the deliveries, but it became apparent that these arrangements would not ensure delivery. Xcel Energy confirmed this concern and began the process of trying to work around the transmission constraint to enable the long-term transactions.

In order to facilitate delivery to the Xcel Energy system, Calpine has expressed a willingness to change the location of their project to a site near Mankato, Minnesota, a location previously considered in the Prairie Island contingent bidding program. Xcel Energy is continuing to negotiate a contract with Calpine based on the new location, however, as anticipated, the project's in-service date will be delayed until at least 2006.

As part of Xcel Energy's effort to address the emerging limitations in short-term power purchases, Calpine and Xcel Energy are discussing the purchase of about 100 megawatts of additional power production capacity to the project. By adding the capability of increasing flue gas temperatures with what is known as "duct firing," additional production capacity can be added to the project.

The Reliant facility in Illinois is existing and therefore cannot be developed in a different location. Reliant has expressed a willingness to complete the negotiation process for a power purchase that would be contingent upon cost-effective transmission improvements necessary to eliminate the Quad Cities constraint. Xcel Energy is investigating the facility improvements that would be required to overcome the constraints. However, it is very unlikely that this matter will be resolved in time to accommodate power deliveries in 2005 or 2006.

Negotiations concerning TransCanada's 155-megawatt combustion turbine proposal to be located near Hutchinson, Minnesota have been difficult, particularly concerning the allocation of risk during the development phase. It is not clear that the parties can overcome these issues. TransCanada estimates their facility could be in service by late 2005 but will not commit to an in service date to meet summer peak demand in 2005.

Negotiations with the selected wind farm developers are also well underway. An agreement for 150 MW with Ivanhoe LLC, an affiliate of PPM Energy, was executed on December 30, 2003. This project includes a flexible construction schedule that will accommodate the completion of transmission improvements necessary to reliably deliver its output off of the Buffalo Ridge. This contract will be submitted to the Commission for approval soon. The Company is negotiating for the other two projects although negotiations have slowed as a result of the expiration of federal production tax credits and other significant business issues. We anticipate negotiations will continue and are hopeful these contracts can still be completed, particularly if the federal energy bill is passed and tax credits are renewed. At the earliest we anticipate these wind projects to achieve operation in 2006 or later. . Regardless of the actual in service dates for these wind projects, they will not add appreciably to the total accreditable production capacity on Xcel Energy's system. During months when peak electrical demand typically occurs, July and August, accreditable capacity from wind farms is in the range of 13 to 25 percent of nameplate capability.

The net effect of these bidding issues has been to reduce the expected resources from the All-Source process available by 2005. The most significant changes are the Minnesota Power withdrawal and the difficulty with the 250 MW purchase from the Reliant Illinois facility. At best, the Reliant purchase will be delayed by two or more years. If the necessary transmission improvements are too expensive or delays are too long, the purchase may not be completed.

In response to these changes, Xcel Energy revisited the shortlist of bidders in the All-Source program to determine if any viable proposals remained that could address the issues that have developed, with an emphasis on 2005 availability. After some initial screening, contacts were made with three bidders. As the result of the effort, discussions are underway with Rainy River regarding the purchase of 157 MW from a peaking facility in Superior, Wisconsin. Rainy River holds all permits and construction authorizations for the facility and has expressed a willingness to complete the project by the summer of 2005. Xcel Energy is attempting to negotiate a contract that would let them proceed, however, as with any complex power purchase agreement, significant issues need to be negotiated.

Xcel Energy continues to seek other potential sources of power from All-Source developers and others as part of our efforts to ensure reliable service. However at this time it is increasingly unrealistic to expect that process will result in new generating resources in 2005.

5.3 Xcel Energy Must Address the Projected Deficit

The net effect of these emerging and changing circumstances related to available resources is that Xcel Energy will probably not be able to secure adequate power supply resources to cover peak demand and associated reserve obligations to the 80th to 90th percentile probability level in 2005 and beyond. Said another way, there is significant risk that the reliability of Xcel Energy's power supply during summer peak demand periods will decline.

The combination of increasing demand and decreasing (2005) or lagging (2006 through 2008) available resources is illustrated in Figure 5-3. The current circumstances result in projected deficits, shown in Figure 5-4, which Xcel Energy must address to maintain System reliability. In 2005 we currently project approximately a 500 megawatt deficit in production capacity. Given the short time remaining between now and the summer of 2005, immediate action is necessary.

5.3.1 Need is for Peaking Service

Base load power plants are typically large capacity facilities designed to run most efficiently continuously and near their design load capability. Peaks in electricity demand are then met by supplementing the base load generation with electricity produced by intermediate units and peaking facilities that are designed to follow shorter-term demand patterns. These units reduce the need to operate base load generating facilities under fluctuating loads when they would be less efficient and more prone to mechanical failure. This concept is shown graphically in Figure 5-5, in what is referred to as a load/duration curve. The demand for electrical power is at or near the peak levels presented in our forecasts for a relatively few hours each year during hot periods. It turns out that the most economical power supply can be maintained by investing in generation with low capital costs but higher operating

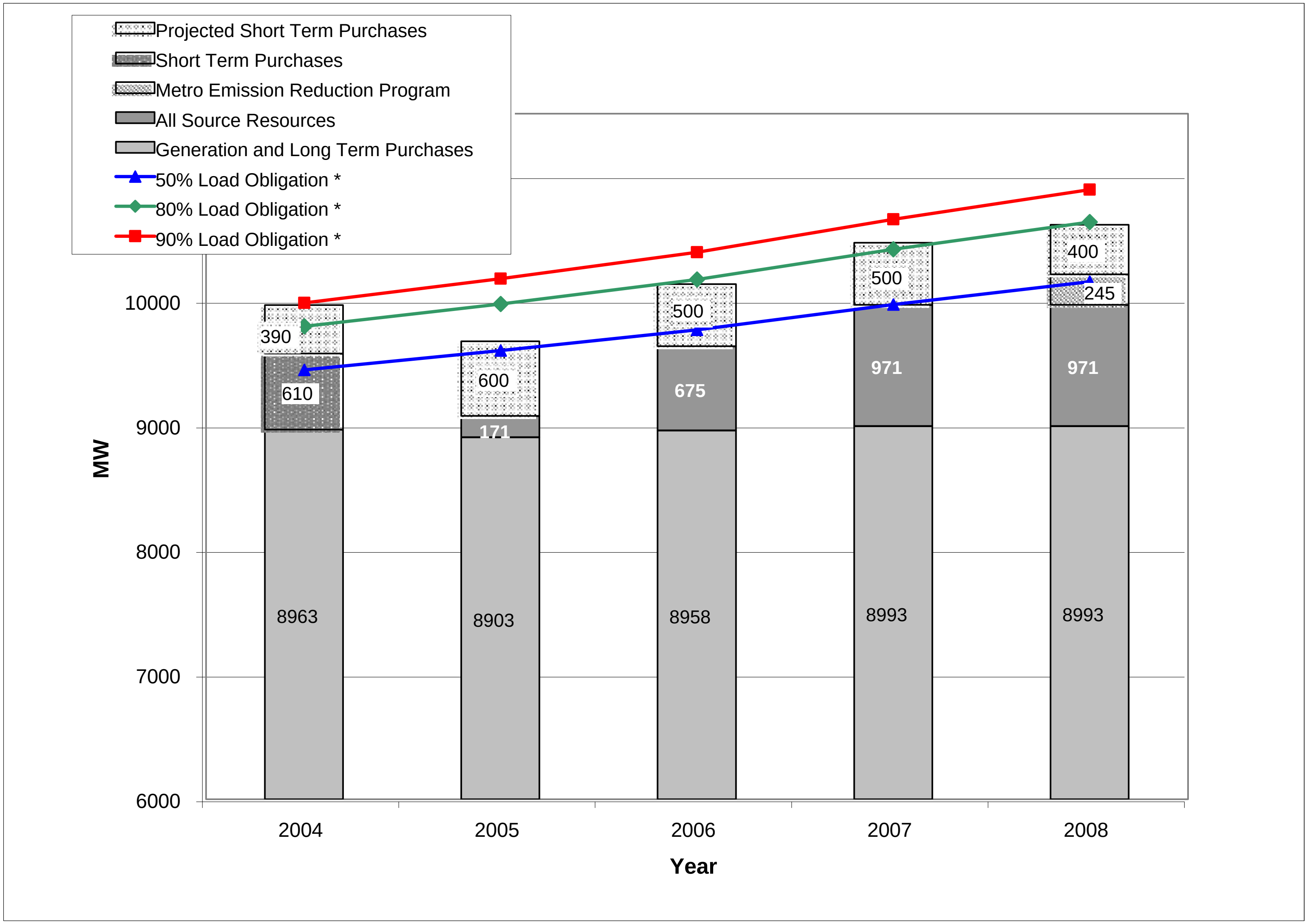


Figure 5-3
LOAD OBLIGATIONS AND RESOURCES
Fall 2003 Forecast
Xcel Energy
Blue Lake Generating Plant
Expansion Project

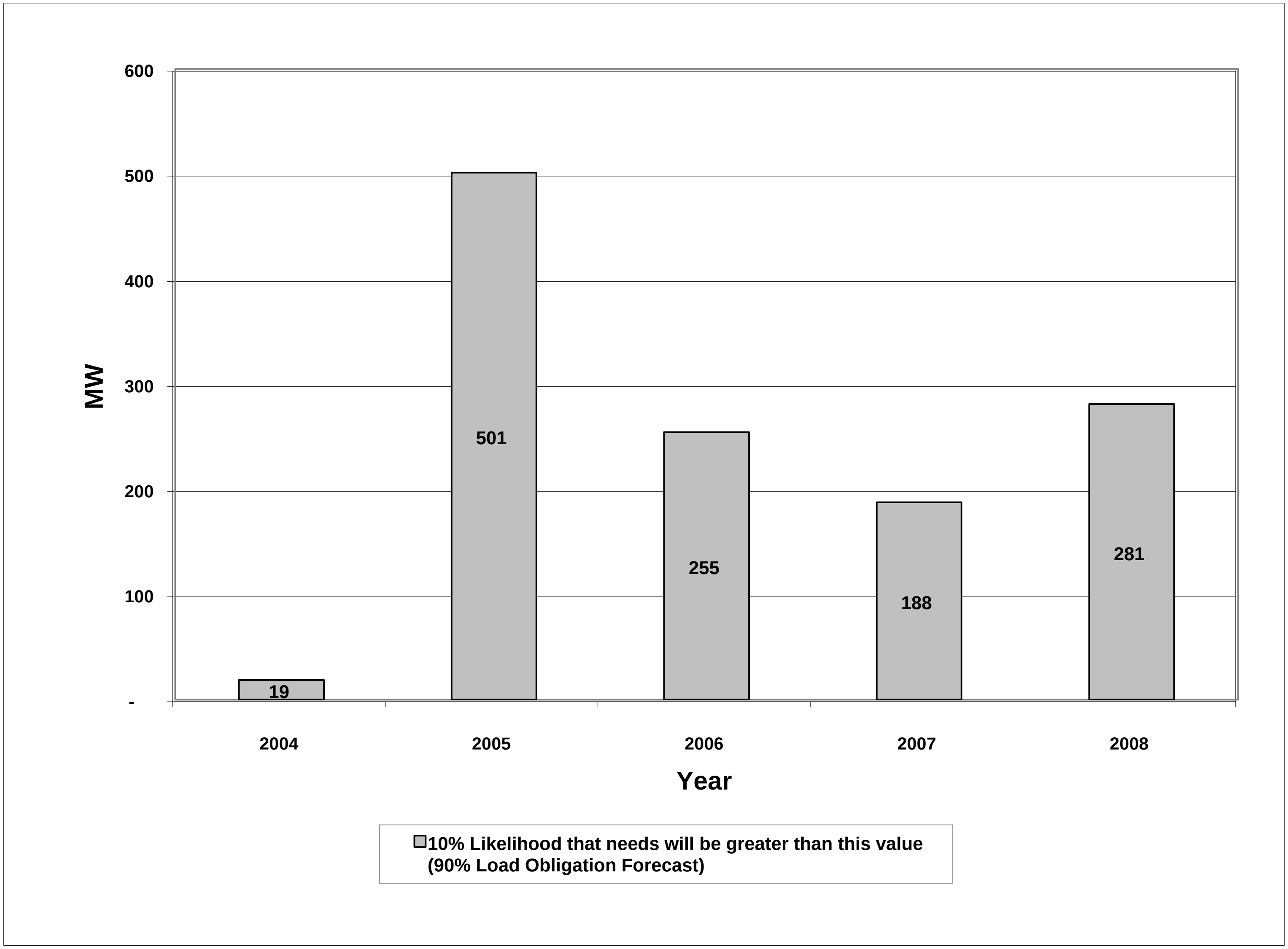


Figure 5-4
NEED SUMMARY
Xcel Energy
Blue Lake Generating Plant
Expansion Project

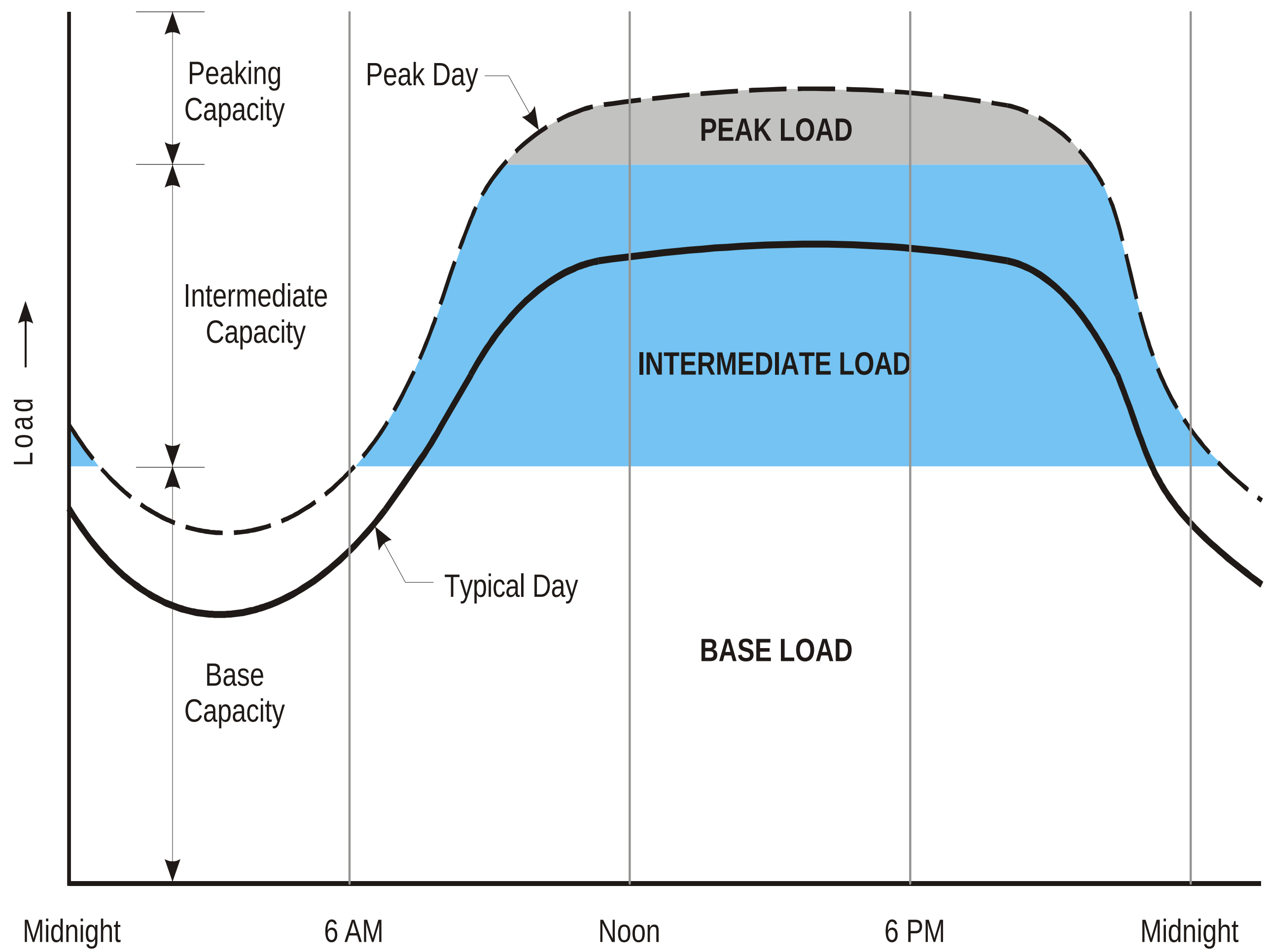


Figure 5-5
TYPICAL LOAD DURATION CURVE
Xcel Energy
Blue Lake Generating Plant
Expansion Project

costs for peaking duty. Simple cycle combustion turbine generators have such characteristics as described in more detail in Sections 3 and 6.

Xcel Energy has completed modeling to simulate future system conditions using the Strategist model[3]. The Strategist model is a generation expansion analysis tool used to find the lowest cost integrated generation plan that meets future electric needs. Inputs to the model are system information such as forecasted demand and energy requirements, reserve obligations, owned and purchased generation (current and planned), and a set of generation alternatives from which the model can choose to meet the future needs. The model is given the choice of base load resources, intermediate duty resources and peaking duty resources and selects the combination and timing of resources that results in the most economical power supply to meet forecasted needs.

The modeling verified that the projected forecast of peak electrical demand and energy requirements on our system is best addressed, with an expansion plan that includes the addition of peaking duty generation capability in 2005.

5.3.2 Need will be Met by Multiple Projects

The proposed Project is one of two peaking plant expansions Xcel Energy is pursuing to address the capacity deficit. The Blue Lake Generating Plant Expansion Project will address about two-thirds of the projected 2005 deficit. Xcel Energy is planning another expansion at its Angus Anson Generating Plant near Sioux Falls, South Dakota. The Angus Anson Generating Plant Expansion Project, which will include the addition of one gas-fired simple cycle combustion turbine with a capacity of approximately 160 megawatts, will address the other third of the forecast deficit.

There remains some uncertainty concerning the availability of transmission capacity to adequately integrate the new Anson unit into the System in 2005. We are currently working with MISO to determine if operating arrangements can be made to share

[3] NewEnergy Strategist, Version 2.1.7, New Energy Associates, LLC.

transmission capacity with wind generators in southwestern Minnesota until improvements come on line in 2007 and beyond.

5.4 Consequences of Project Delay

The capacity deficit summarized in this section (see Figure 5-4) clearly indicates that additional generating capacity is needed in the region by the 2005 summer season. Delay of the Project by one, two or three years would increase the risk to the reliability of Xcel Energy's System and the regional electrical supply.

Maintaining adequate peaking capacity protects the *adequacy* of the regional electric system. Sufficient capacity must be available to meet customer demand for electrical power taking into account planned maintenance outages, unplanned forced outages, unexpected unit retirements due to equipment failure, unit outages for modification or repowering, and unexpected customer demands.

Delay would adversely affect the region's power supply *security* by reducing the ability of the System to withstand sudden disturbances, such as unanticipated loss of System elements, as occurred in the 2003 East Coast Blackout.

Delay would also fail to capture the economic benefits associated with placing the Project in service as soon as possible.

6 An Examination of Alternatives: Project is Most Reasonable and Prudent Alternative

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minnesota Rules 7849.0120). This section addresses the second criterion (Part B) that "a more reasonable and prudent alternative to the proposed facility has not been demonstrated by preponderance of the evidence on the record."

The primary purposes of the Project are to provide Xcel Energy a low-cost, dedicated source of electric power to meet its electric energy demands in its upper Midwest service territory during peak consumption periods and its associated Mid-Continent Area Power Pool (MAPP) Reserve Capacity Obligation (RCO).

Additional peaking capacity will allow Xcel Energy to efficiently meeting short-term increases in customer demand.

Providing additional generating capacity enhances the reliability of Xcel's System and the regional electrical system. Xcel Energy, as a participant in MAPP, must maintain reserve capacity to meet its needs for additional system generating capability.[4] The RCO is currently set at 15% of Xcel Energy's (and other Reliability members of MAPP) maximum demand during the current month and the previous 11 months.[5]

Capacity reserves are designed to *"protect the Adequacy of the Bulk Electric System. They are intended to help ensure that the risk of having insufficient energy to meet customers' demands is kept at an acceptable level.*

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[4] Reserve Capacity Obligation (RCO) is defined in Article 3.53 of the Restated Mid-Continent Area Power Pool Agreement. as "…for any month, the Accredited Capability the Reliability Member is obligated to reserve and use for the purpose of maintaining continuity of service, as established from time to time by the Regional Reliability Committee."

[5] MAPP Generation Reserve Sharing Observations and Recommendations, p. 7, MAPP Reserve Task Force, January 8, 2002.

In other words, [capacity] reserves are intended to ensure that sufficient energy is available to meet customer loads taking into account planned maintenance outages, unplanned forced outages, unexpected unit retirements due to equipment failure, unit outages for modification or repowering, unexpected customer demands, transmission outages that impact energy supply, unusual weather, and acts of nature."[6]

The Project as proposed addresses the Project purposes by applying gas-fired simple-cycle technology at a location that utilizes existing transmission infrastructure. As a result, the Project is more economical, more efficient, more reliable and more environmentally acceptable than other options.

6.1 Alternative Evaluation Criteria

6.1.1 Evaluation Factors

The factors considered in the development of the Project objectives and for evaluation of Project alternatives include the following:

Applicability. The appropriateness of the technology to operation as a peaking duty generating resource is referred to as applicability. As described in Section 5, the resource need that has been identified is for approximately 500 MW of generating capacity that will be called on to operate during times of peak electrical demand, a few hundred hours during the year. To serve in that role a generating resource must be readily dispatchable. Short start up times and responsiveness to changes to demand levels, sometimes called ability to follow load, are desired as well.

Availability. There are three dimensions to the concept of availability in this context. First the technology must be commercially mature and available. A peaking duty resource must be of a proven technology that can operate when called on to do so. Second, the technology must have high availability meaning that it can operate when called on to do so with low forced outage rates.

[6] Ibid, p. 5.

Third, the technology must be of a type that will allow it to meet the schedule requirements of the Project. The electrical system faces considerable risk to its reliable operation if these resources are not in place by the summer of 2005.

Reliability. This is the overall ability of an alternative to enhance the reliability of the bulk electric system. Reliability impact may be measured by an alternative's potential to reduce the frequency, duration and magnitude of adverse effects on the electric supply.

Environmental Impacts. This criterion refers to the effects the alternative is expected to have on the environment. Potential environmental impacts associated with generation technologies include air emissions, effects on land, water consumption, wastewater generation, noise, etc. The potential environmental impacts of the alternatives were compared in our analysis.

Cost and Economic Effects. The alternatives are compared based on cost and other economic effects.

6.1.2 Project Objectives

Specifically, the objectives of the Project corresponding to the evaluation factors discussed in Section 6.1.1 are to:

- Applicability—Meet Xcel Energy's energy demand during peak consumption periods and its associated reserve capacity requirements.
- Availability—Provide a facility that is commercially proven at the several-hundred megawatt scale that can be available for the 2005 summer peak season.
- Reliability—Enhance the reliability of the bulk electric system by ensuring Xcel Energy can meet its reserve capacity obligation.
- Environmental Impacts—Minimizes environmental and community impacts by leveraging existing generation infrastructure and using efficient and environmentally-friendly technology.

- Cost and Economic Effects—Enhance ratepayer value and reduce ratepayer risk by implementing the lowest cost feasible alternative and leveraging existing generation infrastructure, and provide economic benefit to the area community.

The primary objectives are the first two objectives—those that relate to applicability and availability to meet the specific service need in the necessary time frame. The secondary objectives are balancing criteria used to optimize the choice of alternatives that can meet the primary objectives.

6.2 Alternatives Evaluation Methodology

The methodology used to develop and evaluate Project alternatives involves first looking at alternative approaches to meeting the Project objectives and then considering technologies that may fit with the viable approaches. This process is completed in three steps:

1. **Screening**—the feasibility of each alternative approach and each alternative generation technology to meet the primary Project objectives was qualitatively assessed. If an alternative approach cannot meet either of the two primary objectives, that alternative was dropped from consideration.
2. **Screened Alternatives Detailed Information**—The combination of screened approaches and generation technologies were developed in sufficient detail so that the qualitative and quantitative information required by applicable sections of Minnesota Rules 7849 could be compiled and presented.
3. **Alternatives Evaluation**—The Project alternatives, combinations of the screened approaches and generation technologies, were evaluated in more detail in their ability to meet the Project's primary and secondary objectives.

6.3 Approach Screening

The Certificate of Need rules require that the applicant evaluate several alternative approaches to meeting the need that the Project is intended to address. Alternate approaches included in the initial screening include demand side management, increased efficiency of existing facilities, long-term purchased power, short-term purchased power, new transmission lines, reduced project size, alternative site and no facility.

6.3.1 Demand Side Management

Demand side management (DSM) includes both Xcel Energy's Conservation Programs and Load Management Programs that are discussed in Section 5 and presented in detail in Appendix C. These programs will have a substantial positive effect in reducing the demand for additional generating capacity and will substantially reduce energy consumption. However we conclude that additional DSM is not a feasible alternative to the Project.

To date, after thorough review in multiple resource planning dockets, no combination of conservation and load management programming has been found that can completely address all of the growth in demand for electricity in Xcel Energy's system in the upper Midwest. Our resource need projections have been reduced by the Commission's 2000 resource plan DSM goals and rely heavily on achieving them. Annual peak demand increments would be one third to one half higher without the DSM program goals ordered by the Commission.

There is some risk that the overall goals of the DSM program cannot be sustained. While we have been able to meet incremental conservation and load management goals there is some emerging evidence that retention of past DSM capacity reduction effects may be declining.

Finally we do not believe DSM is a feasible alternative in this case due to the short time available for implementation. Our current DSM program has achieved 50 to 100 MW of demand reduction per year. It is not practical to expect that the results of the program can be doubled or tripled in less than a year, the time remaining after the result of the Commission's Need decision. If such an attempt were made, there could be no certainty about the outcome and thus the risk of a shortfall would remain.

6.3.2 Increased Efficiency of Existing Facilities

In 2000, Xcel Energy completed the Black Dog Repowering Project that increased the efficiency of the facility's former Units 1 and 2 by about 45 percent. That project is an example of increasing the efficiency of existing generation units. The Metro Emissions Reduction Project (MERP) is another example of a capital improvement project that will increase the efficiency of Xcel Energy's generation fleet when it is completed by the end of this decade. The effects of these projects have already been considered in the capacity deficit projections. Additional efficiency improvement projects are being evaluated, but as illustrated by some of the examples mentioned here, the implementation of these projects takes several years from conception due to rigorous regulatory and technical review processes as well as construction requirements.

6.3.3 Long-Term Purchased Power

Historically, about 80 percent of Xcel Energy's System load has been met through Xcel Energy's own generation capability and long-term power purchase agreements. Xcel Energy expects to successfully secure over 800 megawatts of additional accreditable production capacity by 2008 through the 2001 All-Source Long-term Resource Acquisition Program.

Securing additional long-term purchases to address the projected deficits starting in 2005 is not practical. Generation capacity that is currently available cannot be utilized because of transmission constraints and those transmission constraints cannot be addressed in time to meet the projected need in 2005. New capacity that may be located in areas that do not have transmission constraints will not be commercially available until 2006 or later. This situation is illustrated by the circumstances that followed Xcel Energy's selection of finalists in the 2001 All-Source Long-term Resource Acquisition Program and discussed in detail in Section 5.2.2.

The issues that have developed in the All-Source program demonstrate that Xcel Energy has made reasonable efforts to procure long-term power purchase agreements to meet the Project need. In spite of Xcel Energy's efforts, the long-term market cannot meet the Project's primary objectives because of transmission constraints and lack of unconstrained generation capacity available in the near-term.

6.3.4 Short-Term Purchased Power

Historically, Xcel Energy has depended on short-term power purchases to cover about the last 10 to 20 percent of its projected capacity needs. Xcel Energy has encountered conditions in the regional market that indicate the same level of short-term power purchases can no longer be achieved.

In 2000, 2001 and 2002 Xcel Energy secured 800 to 1000 megawatts of short-term power purchases to be delivered during the summer peak demand season along with the transmission rights to deliver the contracted electricity. Xcel Energy's 2002 Resource Plan anticipated similar levels of short-term power purchases. Recent inquiries into the market indicate that while the generation resources appear to be available, limited transmission capacity precludes the delivery of power from some generators to Xcel Energy's load centers. These developments are described further in Section 5.2.1.

Xcel Energy will continue to pursue short-term power purchases as they become available but can no longer count on their availability for the foreseeable future. The transmission system constraints that are adversely affecting the ability to deliver power from generation sources preclude short-term power purchases from reliably meeting the Project's primary objectives.

6.3.5 New Transmission Lines

Additions to or improvements in the electric transmission system are not viable alternatives to the Project, primarily because new transmission lines or transmission system upgrades could not be completed in the timeframe necessary to meet the deficit forecasted for 2005.

Conversely, the Project results in minimal new transmission line requirements—a new short interconnection from Blue Lake substation to the existing 230 kV transmission line about 1200 feet south and the addition of some equipment within the existing Blue Lake substation on the plant site, and some reconductoring on existing structures between the Blue Lake and Black Dog Substations.

6.3.6 Reduced Project Size

This approach would consist of developing a project similar to that proposed, except with less capacity. In this case, the most logical reduced size project to consider would be the construction of only one of the two combustion turbine units proposed. This approach would be technically feasible, but would result in a higher unit capacity cost because the economies of scale associated with deploying two turbines at a single site would not be realized.

Furthermore, a reduced project size would be able to meet only a reduced portion of the projected deficit, so alone would not meet both of the Project's primary objectives. Alternative approaches would be necessary in addition to the reduced-size project to address the remainder of the projected deficit.

6.3.7 Alternative Site

Xcel Energy considered other sites in the development of the proposed Project. Xcel Energy is in fact planning a similar expansion at another existing peaking plant site, the Angus Anson Generating Plant site near Sioux Falls (see Section 5.3.2). Other sites do not have the advantage of building at a site already dedicated to electricity generation and that requires no significant transmission system upgrades. Siting the Project at a Greenfield site or at a location requiring construction of new transmission lines would require a longer design, regulatory review process, and construction period; making it difficult if not impossible to meet the need identified in 2005.

6.3.8 No Facility

The alternative of no facility clearly cannot meet the Project's primary objectives. Minnesota Rules 7849.0340 requires the consideration of the "no facility" alternative with a focus on how not building the proposed Project would impact the applicant's existing System committed resources. Information provided in Section 5 of this Application demonstrates that a production capacity deficit will exist in the near term if no action is taken—in other words, Xcel Energy's *"existing and committed generating and transmission facilities"* under a reasonable operating scenario cannot meet the demand for electricity. Such a deficit would greatly reduce the reliability of Xcel Energy's System and the regional electric supply.

6.3.9 Approach Screening Summary

The results of the approach screening are summarized in Table 6-1. None of the many alternative approaches to the Project's approach can meet the Project's primary objectives.

Table 6-1 Alternative Approach Screening Summary

Can this approach effectively and efficiently meet the Project Primary Objectives? + Likely o possibly - Not likely								
	Demand Side Management	**Increased Efficiency of Existing Facilities**	**Long-Term Power Purchases**	**Short –Term Power Purchases**	**New Transmission Lines**	**Reduced Project Size**	**Alternative Site**	**No Facility**
Applicability: Allows Xcel Energy to meet its energy demand during peak consumption periods and its associated reserve capacity requirements.	**o**	**o**	**+**	**+**	**+**	**-**	**o**	**-**
Availability: Provides a commercially proven solution that can meet or reduce the forecast demand by the 2005 summer peak season.	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Is this approach feasible?	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

6.4 Generation Technology Screening

Detailed descriptions of the fossil fuel, renewable resource and other technologies screened along with discussion of the evaluation factors for each technology are presented in Appendix D. A summary and the conclusions of that screening are discussed below.

6.4.1 Fossil Fuel Technologies Screening

Fossil fuel technologies considered in the screening include coal-fired boiler, natural gas-fired combined cycle, natural gas-fired and fuel oil-fired simple cycle (see Sections D.2, D.3, and D.4 of Appendix D). Table 6-2 summarizes the evaluation of each fossil fuel technology's ability to meet the Project's primary objectives.

Table 6-2 Initial Screening of Fossil Fuel Technologies

Can this technology effectively and efficiently meet the Project Primary Objectives? + Likely o possibly - Not likely				
	Coal-Fueled Boiler	**Natural Gas-Fueled Combined Cycle**	**Natural Gas-Fueled Simple Cycle**	**Oil- Fueled Simple Cycle**
Applicability: Meets Xcel Energy's energy demand during peak consumption periods and its associated reserve capacity requirements.	-	o	+	+
Availability: Provides a facility that is commercially proven at the several-hundred megawatt scale that can be available for the 2005 summer peak season.	-	-	+	+
Is further consideration warranted?	No	No	Yes	Yes

The screening evaluation presented in Table 6-2 indicates that coal-fired boiler technology is not able to effectively and efficiently meet the Project's primary objectives. Simple cycle technology has distinct advantages in its application to peaking duty and given the short timeframe necessary to bring a facility into commercial operation.

The coal alternative is eliminated from further consideration due to economics and long lead times for implementation. Coal technology has prohibitively high capital costs for peaking service that will have a low capacity factor. The complexity of operating a coal plants makes operating such a facility in standby mode nearly impossible and prohibitively expensive. The long design and construction lead time for a coal plant makes commercial availability of such a plant by 2005 impossible.

The combined cycle technology is also generally not considered for peaking service due to its relatively high capital cost when compared to simple cycle plants. Although more efficient to operate over longer periods than simple cycle, combined cycle technology is not as well suited to fast startup and short deployments because of the time required to bring the steam side of the plant into operation. The complexity of combined cycle plants and associated permitting and construction makes commercial availability of such a plant by 2005 unachievable.

6.4.2 Renewable Resource Technologies Screening

Renewable resource technologies compared as alternatives to the Project include wind, solar, biomass, hydropower, and landfill gas (see Sections D.5, D.6, D.7, D.8, D.9, and D.9 of Appendix D). Table 6-3 summarizes the evaluation of each renewable resource technology's ability to meet the Project's primary objectives.

Table 6-3 Initial Screening of Renewable Resource Technologies

Can this technology effectively and efficiently meet the Project Primary Objectives? + Likely o possibly - Not likely					
	Wind	**Solar**	**Biomass**	**Hydro-power**	**Landfill Gas**
Applicability: Meets Xcel Energy's energy demand during peak consumption periods and its associated reserve capacity requirements.	-	-	-	+	+
Availability: Provides a facility that is commercially proven at the several-hundred megawatt scale that can be available for the 2005 summer peak season.	-	-	-	-	-
Is further consideration warranted?	**No**	**No**	**No**	**No**	**No**

None of the renewable resource technologies warrant further consideration as an alternative to the Project since they cannot meet the Project's primary objectives. All of these technologies have capacity limitations or are not yet commercially available at the scale represented by the Project.

Despite significant environmental advantages, wind technology is not further considered by the analysis because its lack of reliability makes it unsuitable for peaking service. The reliability of a wind turbine-based generating facility depends on the wind, which is highly intermittent. The objective of the Project to provide on-demand generation for peak load cannot be served by a variable energy non dispatchable resource.

Solar generation has been eliminated from further consideration because of its lack of reliability makes it unsuitable for peaking service. Like wind, solar power generation has real environmental advantages; however, like wind, solar radiation is a variable energy source that is not able to meet the intent of the Project to provide peaking power generation on demand. Geography also plays a role in that Minnesota is not a prime location for significant solar power generation projects. Finally, solar technology has significantly higher costs per kilowatt to install. While solar generation costs may become more competitive in the future, the economics are not expected to improve sufficiently within the time frame identified for the Project.

Biomass is eliminated from further consideration because a biomass-fired plant cannot meet the peaking generation objectives of the Project efficiently. Our experience with biomass operation shows that it is not available in sizes necessary to meet the need. Further, biomass generation takes long lead times to develop. Finally, biomass technology's high capital cost and most efficient application in base load operation make the biomass alternative unattractive to address the Project's objectives.

Hydropower is not a viable alternative technology because of its long lead time. Development of hydropower potential requires a prolonged study to determine environmental and hydrologic impact. New hydropower sites will also require siting of transmission systems through remote areas, which typically require a drawn-out approval process. The Project's primary objectives include near-term need for capacity that hydropower cannot address because of its long development lead times.

Landfill gas (LFG)-fired generation is eliminated from further consideration primarily because potential landfill sites are not large enough to meet the Project's primary objectives.

In conclusion, there are no reasonable renewable energy options that meet the identified capacity and peaking power needs. While Xcel Energy is a strong proponent for renewable energy development in the proper context, we believe in this case the renewable alternatives would not be in the public interest (Minn. Statutes § 216B.2422, Subd. 4.)

6.4.3 Other Technologies Screening

Other technologies compared as alternatives to the Project include fuel cells, microturbines and several energy storage technologies (see Sections D.10, D.11, and D.12 of Appendix D). Table 6-4 summarizes the evaluation of each technology's ability to meet the Project's primary objectives.

Table 6-4 Initial Screening of Other Technologies

Can this technology effectively and efficiently meet the Project Primary Objectives? + Likely o possibly - Not likely			
	Fuel Cells	Micro-Turbines	Stored Energy
Applicability: Meets Xcel Energy's energy demand during peak consumption periods and its associated reserve capacity requirements.	+	+	+
Availability: Provides a facility that is commercially proven at the several-hundred megawatt scale that can be available for the 2005 summer peak season.	-	-	-
Is further consideration warranted?	**No**	**No**	**No**

None of the fuel cell, microturbine nor energy storage technologies warrants further consideration as an alternative to the Project. Fuel cells and microturbines cannot economically address the capacity objectives of the Project. Currently, a large fuel cell or microturbine installation is in the range of 2 MW or less, which is significantly less than the proposed Project capacity. As typically designed, a fuel cell or microturbine driven project would require hundreds of new and not readily available sites to address capacity needs. Power industry opinions vary, but suggest that extensive application of fuel cells and microturbines for power generation is several years away.

Stored energy strategies can impart a degree of energy efficiency by using underutilized generating capacity during off-peak hours for charging the system. Because no system is 100 percent efficient, somewhat less energy will be extracted from the stored system than was originally stored. Energy storage projects require a system with excess or underutilized and economical generating capacity to charge the storage system.

6.4.4 Costs of Generation Alternatives

In addition to the evaluation of generation alternatives against the two primary objectives, economics of generation alternatives are an important consideration. Typical capital costs of generation alternatives are summarized in Table 6-5. Cost information for generation alternatives is discussed in more detail in Appendix D.

Table 6-5 Generation Technology Cost Comparison *

Generation Technology	Typical Capital Cost ($ per kW)
Fossil-fueled Technologies	
Coal-fired Boiler	1,100
Natural gas-fired Combined Cycle	590
Natural gas-Fired Simple Cycle	544-816
Oil-Fired Simple Cycle	991
Renewable Resource Technologies	
Wind	1,000
Solar	4,000
Biomass	1,100-1,840
Hydropower	2,000
Landfill Gas	1,100-1700
Other Technologies	
Fuel Cells	4,000
Microturbines	700-1,100
Energy Storage	Varies

* - See Appendix D – "Alternative Technologies Screening" for specific reference details

6.5 Screened Alternatives Detailed Information

Minnesota Rules 7849.0320 requires that an applicant provide certain detailed information for each LEGF alternative to a proposed project. This section presents that information for the proposed Project and the single alternative that has passed through the technology screening: oil-fired simple cycle technology.

6.5.1 Description

In a simple cycle combustion turbine, incoming air is compressed and mixed with the natural gas or oil fuel. Igniting this mixture results in an expansion of gases (the combustion products and excess air) through a power turbine that in turn drives an electric generator.

The primary difference between a natural gas-fired and an oil-fired simple cycle unit is the additional air pollution control equipment that would be necessary for an oil-fired unit to reduce the emissions to a level comparable to a natural gas-fired unit. Rather than provide that level of added controls, an oil-fired unit would typically have limitations placed on its operating hours to control total air emissions.

For comparison purposes, the detailed information is based on data provided by General Electric for their 7FA simple cycle units. Information is based on two such units being deployed at the Plant. Air pollution controls for the units were assumed as follows:

- Natural gas fired units
  - Dry Low NO_X burners to control emissions of NO_X
  - Gas-only firing to control emissions of NOx, SO_2, PM-10 and CO
  - Good combustion practices to control emissions of PM-10, CO and VOC
- Oil fired units
  - Water injection to control emissions of NO_X
  - Low sulfur fuel oil to control emissions SO_2
  - Good combustion practices to control emissions of PM-10, CO and VOC

6.5.2 Technical Information

Table 6-6 presents the operational data for the Project and the oil fired alternative required by Minnesota Rules 7849.0320, A, B and E through K. Table 6-7 presents the fuel data for the Project and the oil fired alternative required by Minnesota Rules 7849.0320, C.

Table 6-6 Generation Alternatives Operational Information Summary

Item from Minnesota Rules 7849.0320	Proposed Blue Lake Expansion Project Natural Gas-Fired Simple Cycle	Oil-Fired Simple Cycle
Capacity	324 MW	340 MW
Annual Capacity Factor	8 percent	8 percent
Typical Availability	>90 percent	>90 percent
A. Land Requirements	Approx. 20 acres on existing Blue Lake Plant site	Approx. 20 acres on existing Blue Lake Plant site
B. Traffic	No change from current levels	No change from current levels
E. Water Use Max. Pumping Rate Annual Appropriation Annual Consumption	 750 gpm (intermittent) 1.0 million gallons 3.2 acre-feet	 750 gpm (intermittent) 18 million gallons 54 acre-feet
F. Discharges to Water	Water containing dissolved solids present in the raw water source except at a greater concentration to POTW	Water containing dissolved solids present in the raw water source except at a greater concentration to POTW
G. Radioactive Releases	None	None
H. Solid Wastes Produced	Water treatment solids	Water treatment solids
I. Noise	No significant change from current levels	No significant change from current levels
J. Work Force	2-3 FTE	2-3 FTE
K. Transmission Requirements	Met by existing facilities with addition of short new 230 kV interconnection	Met by existing facilities with addition of short new 230 kV interconnection

Table 6-7 Generation Alternatives Fuel Information

Item from Minnesota Rules 7849.0320	Proposed Blue Lake Expansion Project Natural Gas-Fired Simple Cycle	Oil-Fired Simple Cycle
Capacity	324 MW	340 MW
Fuel Type	Natural Gas	No. 2 fuel oil
C (1). Fuel Source	Northern Natural Gas Pipeline	Flint hills Resources Pine Bend Refinery or other refinery source
C (2). Fuel Requirement	2.2 million SCF/hr/unit	100,000 lb/hr/unit
C (3). Heat Input Rate	1,616 million Btu/hr/unit	1,900 million Btu/hr/unit
C (4). Higher Heat Value	1,000 Btu/SCF	18,300 Btu/lb
C (5). Fuel Composition		

Table 6-7 Generation Alternatives Fuel Information

Item from Minnesota Rules 7849.0320	Proposed Blue Lake Expansion Project Natural Gas-Fired Simple Cycle	Oil-Fired Simple Cycle
(a.) Sulfur	2,000 grains/million SCF	<0.05 percent
(b) Ash	None	Trace
(c) Moisture	0.9 lbs./10,000 Btu	Trace

6.5.3 Air Emissions Information

Tables 6-8 and 6-9 presents the air emissions data for the Project and the oil fired alternative required by Minnesota Rules 7849.0320, D.

Table 6-8 Estimated Air Emissions of Generation Alternatives

Pollutant	Estimated Emission Rates (lbs./MWh)	
	Proposed Blue Lake Expansion Project Natural Gas-Fired Simple Cycle	Oil-Fired Simple Cycle
SO_2	0.003	0.027
NO_X	0.036	0.17
PM_{10}	0.005	0.009
CO	0.019	0.030

Table 6-9 Comparison of Generation Alternative Impacts to Ambient Air Quality

Pollutant	Ambient Air Quality Standard	Estimated Contribution to Ground-level Concentrations	
		Proposed Blue Lake Expansion Project Natural Gas-Fired Simple Cycle ($\mu g/m^3$)	Oil-Fired Simple Cycle ($\mu g/m^3$)
SO_2 (Annual)	80	<0.1	Higher
SO_2 (24-hour)	365	<1	Higher
SO_2 (3-hour)	1300	<1	Higher
SO_2 (1-hour)	1300	<1	Higher
NO_X (Annual)	100	<1	Similar
NO_X (24-hour)	None	<1	Higher
PM_{10} (Annual)	50	<1	Higher
PM_{10} (24-hour)	150	<0.1	Higher
CO (24-hour)	None	<1	Similar
CO (1-hour)	40,000	<1	Similar
CO (8-hour)	10,000	<1	Similar

See Appendix A for other modeling assumptions.

6.5.4 Economic Information

An itemized cost comparison of the Project and the oil-fired alternative as required by Minnesota Rules 7849.0320, C is presented in Table 6-10. The analysis estimates the total unit cost of energy (2003 dollars per kilowatt-hour) that would be provided under each of the alternatives. The total unit energy cost depends upon several operational assumptions. Those operational assumptions—noted in Table 6-10—are consistent with anticipated operation of the Project described in Section 3.6. Specifically, the cost analysis assumes the Project will operate at an 8 percent capacity factor. The cost analysis presented in Table 6-10 is a present value analysis with costs presented in 2003 dollars—therefore, no escalation factor is applied to the fuel costs and operations and maintenance costs.

Table 6-10 Generation Alternatives Cost Comparison

No.	Item	Units	Natural Gas Fired Simple-Cycle	Oil Fired Simple-Cycle	Comments
Input Assumptions					
1	Base Capacity	MW	324	340	ISO Conditions (162 MW each unit)
2	In-service Date	Calendar Year	2003	2003	Used for cost analysis only--actual in-service date expected to be Spring 2005
3	Service Life	Years	30	30	
4	Level Annual Revenue Requirement (LARR)	Percent	11.53%	11.53%	
5a	Capacity Factor	Percent	8	8	Operating Time (hrs)/ 8760 (hrs/year)*100
5b	Annual Operating Time	Hours	669	669	Anticipated hours at nominal capacity
5c	Heat Input	million Btu/hour	3134	3369	Based on turbine manufacturer data
6	Construction Cost	2003 $/kW	300	360	2003 cost basis
7	Fixed O&M Costs	2003 $/kW-year	9.23	12.00	Source: Internal Xcel market information
8a	Fuel Costs	2003 $/million Btu	5.22	6.87	Source: Internal Xcel market information
8b	Non-fuel Variable O&M Costs	2003 $/kW-hour	0.0003	0.0004	Source: Internal Xcel market information
Capacity (Annualized Fixed) Costs					
11	Total Plant Capital Cost	2003 $	97,200,000	122,400,000	Capacity (MW)*Construction Cost ($/kW)*1000(kW/MW)
12	Annual Capital Recovery	2003 $	11,207,160	14,112,720	LARR (percent)*Total Plant Capital Cost (2003 $)
13	Annual Fixed O&M	2003 $	2,990,520	4,080,000	Fixed O&M Costs($/kW-
14	Total Annual Fixed Costs	2003 $	14,197,680	18,192,720	Annual Capital Recovery (2003$) + Annual Fixed O&M (2003$)
15a	Project Capacity Cost	2003 $/kW	43.82	53.51	Total Annual Fixed Costs (2003 $)/Capacity (MW)/1000 (kW/MW)
15b		2003 $/kW-hour	0.066	0.080	Total Annual Fixed Costs (2003 $) / Capacity (MW) / 1000 (kW/MW) / Annual Operating Time (hours)
Energy (Variable) Costs					
18	Net Annual Generation	MW-hours	217,000	227,000	Capacity (MW)*Annual Operating Time (hours)
19	Annual Fuel Consumption	million Btu	2,097,000	2,254,000	Heat Input (million Btu/hour)*Annual Operating Time (hours)
20	Annual Fuel Cost	2003 $	10,946,000	15,485,000	Fuel Cost (2003 $/million Btu)*Annual Fuel Consumption (million Btu)
21	Annual Non-fuel Variable O&M Cost	2003 $	65,000	91,000	Non-fuel Variable O&M Costs (2003 $/kW-hour)*Capacity (MW)*1000 (kW/MW)*Annual operating Time (hours)
22	Total Project Variable Generation Cost	2003 $	11,011,000	15,576,000	Annual Fuel Cost (2003 $) + Annual Non-fuel Variable O&M Cost (2003 $)
23	Project Energy Cost	2003 $/kW-hour	0.051	0.069	Total Variable Generation Cost (2003 $) / Net Annual Generation (MW-hours) / 1000 (kW/MW)
27	**Total Cost**	**2003 $/kW-hour**	**0.116**	**0.149**	Total Capacity Cost (2003 $/kW-hour) + Total Energy Cost (2003 $/kW-hour)

6.6 Alternatives Evaluation: Project is Best Option

The evaluation of the generation alternatives' ability to meet the Project objectives is summarized in Table 6-11. The Project is the best option for meeting those objectives as discussed further below.

Table 6-11 Summary of Alternatives Evaluation

Does this alternative effectively meet the Project Objectives?

+ Yes **o** Somewhat, possibly **-** No

Project Objective	Proposed Blue Lake Expansion Project Natural Gas-Fired Simple Cycle	Oil-Fired Simple Cycle
1. **Applicability**: Meets Xcel Energy's energy demand during peak consumption periods and its associated reserve capacity requirements.	+	+
2. **Availability**: Provides a facility that is commercially proven at the several-hundred megawatt scale that can be available for the 2005 summer peak season.	+	+
3. **Reliability**: Enhances the reliability of the bulk electric system by reducing the frequency, duration and magnitude of potential adverse effects on the electric supply.	+	+
4. **Environmental Impacts:** Minimizes environmental and community impacts by leveraging existing generation infrastructure and using efficient and environmentally-friendly technology	+	-
5. **Economic Effects**: Enhances ratepayer value, reduces ratepayer risk, increases Xcel Energy asset value by leveraging existing generation infrastructure, and provides economic benefit to the area community.	+	o

6.6.1 Best for Service Need

The Project is the best option for addressing Xcel Energy's peaking service need and its associated reserve capacity requirements. The simple cycle technology is well-suited to meet the reserve capacity and peaking load objectives of the Project because of its ability to be brought into service quickly and operated for short durations. In contrast, the coal-fired boiler and combined cycle technology-based generation alternatives cannot be as efficiently operated with quick start up and short-duration service.

The most frequently used alternative approach in the past, short-term purchased power, cannot reliably meet the Project's service need objective because of the unavailability of firm transmission rights.

6.6.2 Most Timely

The Project is the best option because it is commercially proven at the several hundred MW scale and can meet a commercial in-service date target of Summer 2005. Simple cycle plants are currently the most common technology used for new generation and can be brought on line within 12 months.

Alternative approaches are less likely to satisfy the Project timeliness objective because most alternatives would depend upon new transmission facilities. New transmission lines would take several years to site.

Alternative technologies are typically more complex and cannot be procured and constructed in the required timeframe.

6.6.3 Best for System Reliability

The Project is the best option to enhance the reliability of the bulk electric system. Simple cycle technology is among the most reliable generation technologies. The Project will include firm gas supply contracts to address fuel reliability without the need for a backup fuel oil supply.

Locating the Project within the metropolitan Twin Cities' transmission beltway also enhances System reliability by placing the resource closer to the load, reducing strain on an already taxed regional transmission system.

6.6.4 Best for Environment

The Project is the best option to minimize environmental and community impacts by leveraging existing generation infrastructure and using efficient and environmentally-friendly technology. The simple cycle technology that will be employed by the Project would have the least overall environmental impact of the feasible alternatives. Air emissions from a natural gas-fired simple cycle are significantly lower than the oil-fired alternative. No new land would be taken for the Project. Purchased power would likely result in land being consumed for new generation and transmission lines elsewhere.

6.6.5 Most Cost-Effective

The Project is the best option to enhance ratepayer value and reduce ratepayer risk by leveraging existing generation infrastructure and provide economic benefit to the Blue Lake area community. The economic analysis of the generation alternatives presented in Sections 6.4.4 and 6.5.4 indicates the Project is most beneficial for Xcel Energy ratepayers. The Project also protects Xcel Energy customers from short-term energy price volatility. The Project also leverages existing investment in the Blue Lake Plant by utilizing existing components of the Plant for the Project. The Project also provides benefit to the local economy through payment of local property taxes.

7 Project Benefits Society

The Project will benefit society by meeting overall state energy needs in an economically and environmentally responsible manner thereby supporting future development in Minnesota and the region.

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minnesota Rules 7849.0120). This section addresses the third criterion (Part C) that "by a preponderance of the evidence on record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a matter compatible with protecting the natural and socioeconomic environments, including human health."

7.1 Customers Statewide Benefit from Reliable Power

Capacity provided by peaking facilities provides a source of reserve generating capacity and thereby enhances system reliability. Peaking facilities allow system operators to optimize, from an efficiency and environmental perspective, the generating options for a variety of demand situations.

The Project also increases system reliability by locating generation capability as close to load as possible. This is especially true when transmission line expansion is difficult as it is today. The Project gives Xcel Energy additional capacity close to load that can economically generate more energy and increases Xcel Energy's capacity within its largest load center, the Twin Cities area.

The Project will add more modern technology to Xcel Energy's generation portfolio. Natural gas-fired simple cycle generation is among the most reliable technology for peaking service demands. The Project will complement Xcel Energy's 22 electric generation facilities that use a variety of technologies and fuels including, coal, oil, natural gas, hydro, refuse derived fuel (RDF) and nuclear. Wind and landfill gas technologies are also included in Xcel Energy's portfolio through power purchase agreements. This wide range of generation capabilities provides Xcel Energy's customers in Minnesota and surrounding states with reliable and economical electrical energy supply.

7.2 Project Provides Protection from Short-term Power Purchases Uncertainty

Since the issuance of FERC Order 888 in 1998, the wholesale electric power market has undergone a rapid transformation to a competitive environment. Where utilities formerly bought and sold energy based on cost, energy is now sold for whatever the market will bear. As evidenced by the price fluctuations and accompanying spikes over the last several summers in the MAPP/MISO region (in the Midwest), this transformation to a competitive market has congested the transmission system and exposed electricity consumers to new risks. Xcel Energy, being a net purchaser of energy in the summer months, has been particularly vulnerable. Xcel Energy is taking a number of steps, including the Project, to address this problem.

The Project adds significant value in the form of protection from uncertainty associated with short-term power purchases in the current market. This value has been highlighted over the last several summers, where wholesale market prices for energy have reached extremely high levels during brief periods and more recently when transmission constraints have limited access to short-term energy resources.

7.3 Provides Value to Rate Payers

The Project is the most cost-effective of the feasible alternatives to meet the Project objectives, particularly the ability to provide electric power during peak consumption periods and meet the MAPP RCO within the needed timeframe. The economic analysis presented in Sections 6.4.4 and 6.5.4 demonstrates that the Project is cost-competitive when compared to alternatives.

7.4 Effectively and Efficiently Uses Existing Infrastructure

The Project involves the expansion of an existing generating station allowing Xcel Energy to take advantage of existing infrastructure. The CTGs will be placed within the existing plant footprint, so will require no new land area beyond that already part of the existing facility.

The Project will be able to use the Plant substation with some modification and the electric transmission lines that currently serve the facility with only a short new transmission interconnection. An interstate gas pipeline is located approximately 10 miles from the site and is available to provide adequate gas supply for the Project (see Figure 1-2).

7.5 Best Fit to Existing Transmission Facilities

Only a short new transmission line interconnection to the existing metropolitan Twin Cities beltway transmission system is required to accommodate the increase in generating capacity at the Blue Lake Generating Plant site. Cost comparisons ($/kW) of outlet developments at various sites strongly indicate that the Blue Lake Plant is a very attractive site for increased generation capacity from a bulk transmission economics perspective. Currently, one 115- and one 345-kV lines provide transmission outlet which is adequate to accommodate an incremental 324 MW generation addition without creating a need to upgrade or build new transmission. Based upon preliminary viability analysis, bulk system reliability is maintained (adequacy and security) without any degradation in transmission system performance, thereby rendering this a highly preferred site when compared to other options in the region.

7.6 Creates Lower Emissions than Feasible Alternatives

The Project will generate the least air emissions and the least impact to ambient air quality of all feasible alternatives to meet the Project objectives. The specific comparisons of emissions and impacts to ambient air quality, discussed in Section 6.5.3, demonstrate that the Project has lower air emissions when compared directly to alternatives.

7.7 Creates Jobs

Construction of the Project will require an estimated 90-120 construction workers over the one-year Project construction period. These high-skill, high-paying positions, including, pipefitters, iron workers, millwrights, boilermakers, as well as carpenter, electrician and other trades, will add as much as $8 million of payroll into the regional economy.

Operation of the new CTGs after the Project construction will require approximately 2-3 full-time positions.

7.8 Provides Tax Revenues

The Project and the rest of the Plant will contribute significantly to the City of Shakopee, Scott County, the Shakopee School District, and the Metropolitan Council seven-county fiscal pool in the form of taxes and other fees. The State of Minnesota and Scott County will also benefit from income and sales taxes paid as a result of the construction of the Project. The operating staff associated with the Plant will also pay payroll taxes.

7.9 Supports Future Economic Development

Historically, Xcel Energy has maintained low electric rates relative to utilities in other regions of the United States. As a result, Minnesota has been able to attract industrial concerns and maintain steady economic growth. The Project will allow Xcel Energy to maintain favorable rates to support future development in Minnesota and surrounding states.

8 Project Complies with Rules and Policies

The Project serves overall state energy needs, fosters state energy policy and complies with all applicable rules and regulations.

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minnesota Rules 7849.0120). This section addresses the second criterion (Part D) that "the record does not demonstrate that the design, construction, or operation of the proposed facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments."

8.1 Project is Consistent with Minnesota Energy Policy

8.1.1 Legislative Preference

The Minnesota legislature has found that:

> *"The following energy sources for generating electric power distributed in the state, listed in their descending order of preference, based on minimizing long-term negative environmental, social, and economic burdens imposed by the specific energy sources, are:*
>
> *(1) wind and solar;*
>
> *(2) biomass and low-head or refurbished hydropower;*
>
> *(3) decomposition gases produced by solid waste management facilities, natural gas-fired cogeneration, and waste materials or byproducts combined with natural gas;*
>
> *(4)* **natural gas***, hydropower that is not low-head or refurbished hydropower, and solid waste as a direct fuel or refuse-derived fuel; and*

(5) coal and nuclear power." [7] (emphasis added).

The first three sources cannot meet the objectives of the Project listed in Section 6.1. The natural gas fueled Project is consistent with Minnesota policy because the Project:

- Uses the most efficient generation technology available to address the Project need, and
- Minimizes *"negative environmental, social and economic burdens imposed by the specific energy sources"* when compared to feasible fossil-fueled alternatives.

8.1.2 Department of Commerce Policy

The Project serves the State energy policy goals as stated in the Minnesota Department of Commerce publication *Energy Policy & Conservation Report 2000*. The five goals stated in the publication are:

1. *The energy system in Minnesota must maintain and improve reliability for the long term.*
2. *Energy conservation is vital for Minnesota's energy future.*
3. *Minnesota's energy future must be built on the most cost effective, least environmentally damaging resources.*
4. *Minnesota's energy resource mix in the future must become more diversified … to relieve strain on transmission and distribution infrastructure and to ensure greater reliability of the system.*
5. *To achieve and maintain true reliability, energy must be affordable for all Minnesotans.*

The Project clearly serves four of these five goals. (The Project is not designed to promote energy conservation, as conservation in and of itself does not qualify to meet the MAPP RCO. Xcel Energy has, as approved by the MN PUC, adopted policies to promote energy conservations as part of its on-going business.) By utilizing natural gas

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[7] Minnesota Statutes 216C.051, Subd 7, ¶ (c) and (d).

to upgrade and increase the capacity of existing generation infrastructure, the Project will improve the reliability of the states energy infrastructure, produce the least environmental damage, and improve the diversity of Minnesota's energy resource mix. The Project will provide generation capability to meet the Project objectives using the most efficient applicable technology, which will result in cost-competitive reserve capacity and peaking energy.

8.1.3 Non-Proliferation Policy

The Project will take advantage of existing infrastructure for all aspects of the Project from fuel supply, to generation, and through transmission. The Project will largely use existing high-voltage electric transmission facilities to transport the electric energy generated by the Project, with only minor upgrades to the system. This use of existing transmission facilities is consistent with the State of Minnesota's commitment to non-proliferation of transmission corridors.[8]

8.2 The Project Complies with Federal and State Environmental Regulations

The Project will meet or exceed the requirements of all applicable federal and state environmental laws and regulations. Section 2.2 provides a list of permits and approvals the Project must obtain from government entities in support of full compliance.

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[8] People for Environmental Enlightenment and Responsibility (PEER) v. Minnesota Environmental Quality Council, 266NW2d858 (Minn. 1978)

Appendices
to
Certificate of Need Application for the
Blue Lake Generating Plant Expansion Project

List of Appendices

Appendix A Air Emissions Modeling

Air Emission Dispersion Modeling
for the
Blue Lake Generating Plant Expansion Project

Air emissions dispersion modeling was conducted using the EPA-approved model ISC3-PRIME (ISC3P version 99020) to predict ambient air concentrations of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter less than 10 microns in size (PM_{10}), and carbon monoxide (CO). Concentrations were predicted for averaging periods specified by National and State Ambient Air Quality Standards; a 24-hour average was added for NO_x and CO based on Certificate of Need (CON) requirements. Assumptions for the modeling scenarios are listed below.

A.1 Comparison of Contributions to Ambient Air Quality

The contributions to ambient air quality from the existing Blue Lake Generating Facility and from the existing Blue Lake Generating Facility **plus** the Project are shown in Table 4-2 of the CON application. As shown in Table 4-2, there is no change in the maximum modeled ambient air concentrations from the facility as a result of the Project. Another way of wording that result is that the modeled impacts from the new CTGs do not contribute to the overall concentration at the specific model receptor associated with the maximum impact from the facility.

A.1.1 Dispersion Modeling Approach

In general terms, the dispersion model calculates ambient air concentrations at model receptor points from inputs of stack data (height, flow rate, temperature) and hourly meteorological data (wind speed, wind direction, temperature, atmospheric stability). The existing facility includes four CTGs (EU 001 – 004), an emergency generator (EU 005), and a diesel firepump (EU 006) – all sources with different stack parameters than the new CTGs.

The model receptor points are selected so that there is sufficient coverage near the facility and out some distance away from the facility. As shown in Figure A-1, the modeling receptor grid included receptors spaced at 25 meter intervals along the fenceline, at 200 meter intervals out to 2 kilometers from the facility, and at radial distances of 3, 4, 5, and 10 kilometers from the facility with receptors at 10 degree intervals.

A.1.2 Modeling Inputs

The modeling inputs are based on anticipated operation:

- For ambient air quality standards annual averages, annual emissions from the current facility are based on year 2000 emissions. Emission rates for the Project are based on potential utilization of 1,339 hours/year. To avoid any question as to what the worst-case apportionment of emissions between the two new CTGs is and as an additional level of conservatism in the modeling, both CTGs were assumed to operate for 1,339 hours per year.

- For ambient air quality standards short term averages, maximum base load hourly emission rates are used for both the existing facility and the new turbines.

- Actual stack height for turbines 1 through 4 and anticipated stack heights of 50 feet for the new CTGs.

- Project inputs for criteria pollutant emissions, heat input, exit temperature and air flow are from General Electric data.

- Inputs for the existing sources were obtained from facility data for heat input, exit temperature, air flow, stack height, and stack diameter. Pollutant emission rates were developed using USEPA emission factors (AP-42) for the appropriate source and heat input types.

- A five-year meteorological data set (1987 through 1991) from the National Weather Service with Minneapolis-St. Paul Airport surface data and St. Cloud upper air data (meteorological data used historically for air quality permitting).

- Same receptor grid as used previously for air quality modeling (see Figure A-1).

A.2 Comparison of Project to Alternatives

Table 6-9 of the CON application shows the maximum modeled concentrations from the Project gas-fired CTGs with a qualitative comparison to modeled concentrations from simple cycle oil-fired CTGs. As shown in Tables 6-8 and 6-9, emissions are generally higher from oil-fired CTGs than from natural gas-fired CTGs. The annual average NOx concentrations are given as similar in Table 6-9 because the Project will be limited to 39.5 tons per year of NOx emissions. This limit is independent of fuel type.

The short-term CO concentrations are given as higher for the Alternative in Table 6-9. During start-up (which lasts less than one hour for each unit), CO emissions are similar for both the Project and Alternative. CO emissions during start-up are higher than during base-load operations. Table 6-9 reflects base-load emissions.

The maximum modeled concentrations from the Project (by itself) occur at different receptors and for different meteorological conditions than the maximum modeled impact from the existing facility; therefore, the concentrations given in Table 6-9 are not additive with the modeled concentrations given in Table 4-2.

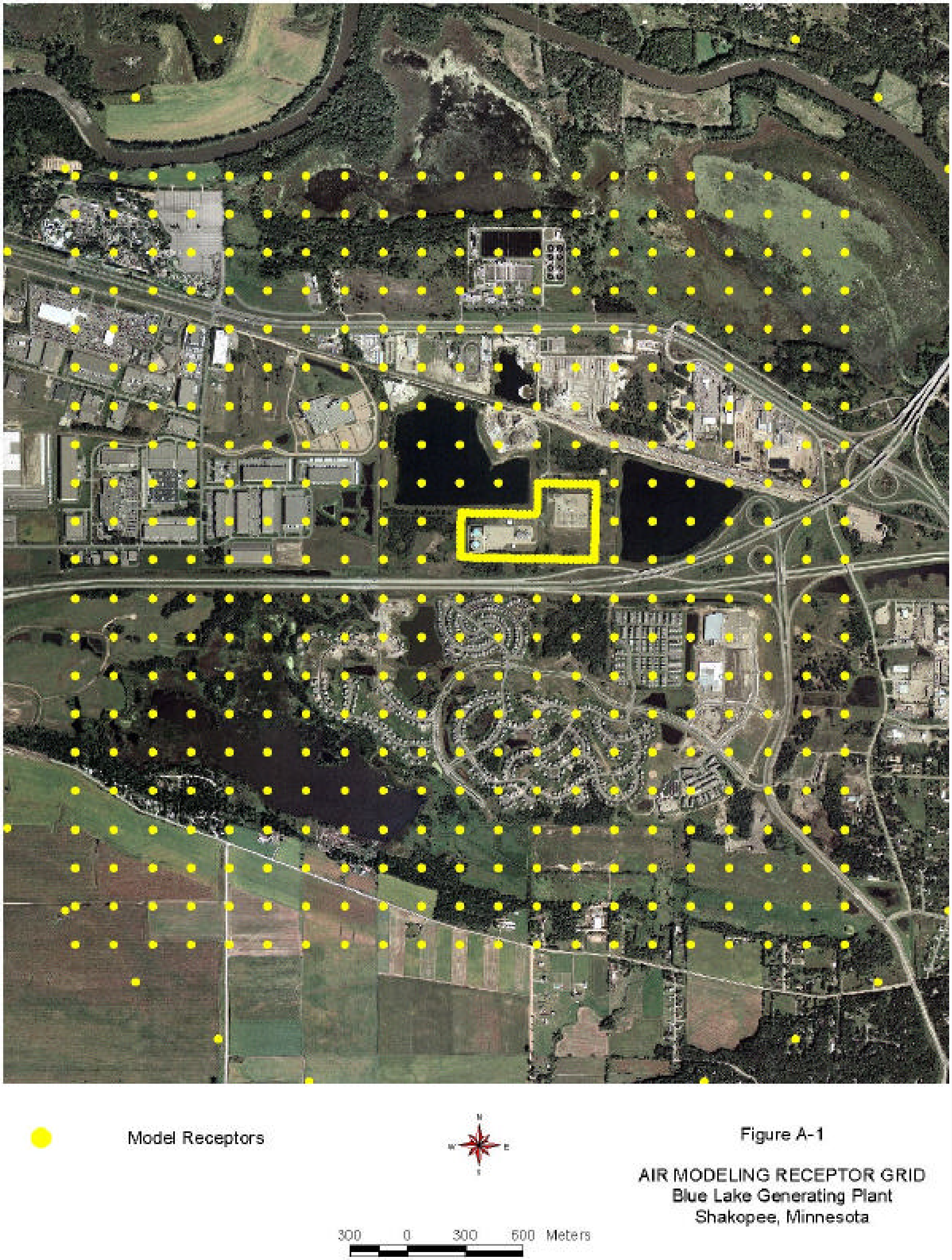

Figure A-1

AIR MODELING RECEPTOR GRID
Blue Lake Generating Plant
Shakopee, Minnesota

Appendix B Xcel System Demand and Capability Data

B.1 Overall Methodological Framework

Xcel Energy prepared its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. Xcel Energy has five jurisdictions: Minnesota, North Dakota, South Dakota which comprise the legal entity Northern States Power-Minnesota and Wisconsin and Michigan which comprise the legal entity Northern States Power-Wisconsin. The overall methodological framework is "model oriented". The forecast is referred to as the Native Energy and Peak Demand Forecast (August 2003).

B.2 Specific Analytical Techniques

1. Econometric Analysis. Xcel Energy used econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter of the following:
    a. Residential without Space Heating
    b. Residential with Space Heating
    c. Small Commercial and Industrial
    d. Large Commercial and Industrial

    Trend analysis was used for the "Other" sectors, which includes Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental sales, and Municipals (firm Wholesale).

2. Judgment. Judgment is inherent to the development of any forecast. Whenever possible, Xcel Energy tries to use quantitative models to structure its judgment in the forecasting process.

3. Loss Factor Methodology. Loss factors by legal entity were used to convert the sales forecasts developed in section B.1 into system energy requirements (at the generator).

4. Peak Demand Forecast. Econometric analysis was used to develop a total system Mw demand forecast for the entire forecast period.

The MWh sales forecast was developed for each customer class and jurisdiction based on the techniques discussed in section B.1. Summing the various jurisdictional class forecasts yields the total system sales forecast. A monthly loss factor is applied to convert MWh sales to MWh native energy requirements. An econometric model was developed to forecast MW peak demand for the Xcel Energy North system, using independent variables such as native energy requirements, peak producing weather, seasonal and binary variables.

1. Sales Forecasts. Sales forecasts are estimates of MWh levels measured at a customer meter. They do not include line or other losses.

2. Native Energy Requirement Forecasts. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts. A system loss factor for each legal entity, developed based on average historical losses, was applied to the sales forecast to calculate total losses. The sum of the MWh sales and losses equal native energy requirements.

3. Peak Demand Forecasts. Xcel Energy estimates peak demand using an econometric model with native energy requirements, weather, seasonal and binary series as independent variables.

B.3 Statistical Techniques and Models Used

1. Residential Econometric Models. Xcel Energy's sales to the residential sectors represent about 29 percent of its total retail electric sales in 2002. Residential sales are divided into with and without space heating customer classes for each jurisdiction. Ordinary Least Squares models using historic data were developed for each residential sector. A variety of independent variables were used in the model, including:
   - Number of customers
   - Personal income
   - Price of electricity, residential class
   - Actual heating and temperature humidity index (THI) degree days
   - Binary seasonal variables

2. Small Commercial and Industrial Econometric Models. The small commercial and industrial sector represents about 41 percent of Xcel Energy's retail electric sales in 2002. The models are ordinary least squares regressions using historic data. The models include a combination of variables, including the following:
   - Number of small commercial and industrial customers
   - Price of electricity, small commercial and industrial class
   - Gross State Product for respective jurisdiction
   - Actual heating and temperature humidity index (THI) degree days
   - Indicator variables (i.e. billing system conversion)

3. Large Commercial and Industrial Econometric Models. Sales to the large commercial and industrial sector represent about 29 percent of Xcel Energy's retail electric sales in 2002. The models are OLS regressions using historic data and a combination of variables, including the following:
   - Regional employment by sector
   - Price of electricity, large commercial and industrial class
   - Actual heating and temperature humidity index (THI) degree days
   - Indicator variables such as billing system conversion, etc.

4. Municipals. The municipal class is forecast using separate trend analysis at the individual customer level for the Minnesota Company and Wisconsin Company. The forecast of these municipal customers only includes those that Xcel Energy is committed to serve, i.e., only the firm wholesale customer usage.

5. Others. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a very small portion of the total sales, trend analysis was used and very little growth was forecast.

6. Peak Demand Model. An econometric model was developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:
   - Native energy requirements
   - Peak-producing weather by month
   - Monthly binary variables

B.4 Forecast Confidence Levels

Xcel Energy developed probability distributions around total MWh native energy requirements and Mw peak demand. Using an upper and lower bandwidth produced by the modeling software used to create the peak demand and native energy forecast, an annual standard error for each model was determined and confidence levels established.

Over the last five years, annual peak demand and electric consumption deviation from expected levels is within an acceptable range.

B.5 Methodology Strengths and Weaknesses

The strength of the process Xcel Energy used for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how Xcel Energy's system is growing and should enable better decisions in the areas of generation, transmission, marketing, conservation, and load management.

Regarding accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk of the forecasts and develop plans that are robust over a wide range of future outcomes.

B.6 Methodology Changes

The methodology used by Xcel Energy to create native energy and peak demand forecasts has transitioned from a "top-down" approach to a "bottom-up" method. In forecasts prior to the 2002 Integrated Resource Plan, Xcel Energy created a total system MWh sales estimate by class and allocated to the various jurisdictions. In response to comments from Department of Commerce staff regarding the 2000 Integrated Resource Plan, and in an effort to standardize methodologies across its entire service territory, Xcel Energy has developed independent class models for each jurisdiction. In addition, Xcel Energy now has one set of models for the entire forecast period, eliminating the need to calibrate its long-term planning forecast to its short-term financial forecast.

B.7 Data Definitions

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

Jurisdiction Abbreviations

M or MN	State of Minnesota
N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin
Mi or MI	State of Michigan

Monthly MWh Sales Series

ERX(Juris)	Residential without space heating for given jurisdiction
ERH(Juris)	Residential with space heating for given jurisdiction
ESC(Juris)	Small commercial and industrial for given jurisdiction
ELC(Juris)	Large commercial and industrial for given jurisdiction

Monthly Customer Series

NRX(Juris)	Residential without space heating for given jurisdiction
NRH(Juris)	Residential with space heating for given jurisdiction
NSC(Juris)	Small commercial and industrial for given jurisdiction
NLC(Juris)	Large commercial and industrial for given jurisdiction

Monthly Price per MWh Series

PRX(Juris)	Residential without space heating for given jurisdiction
PRH(Juris)	Residential with space heating for given jurisdiction
PSC(Juris)	Small commercial and industrial for given jurisdiction
PLC(Juris)	Large commercial and industrial for given jurisdiction

Monthly Economic and Demographic Series

(Juris)HH	Number of Households in given jurisdiction
(Juris)GSP	Gross State Product for given jurisdiction
EEA_(Juris)	Total non-farm employment in given jurisdiction
EM_(Juris)	Total manufacturing employment in given jurisdiction
EnonM_(Juris)	Total non-manufacturing employment in given jurisdiction
YP96@(Juris)	Personal income in given jurisdiction

Monthly Weather Variables

H65(Suffix)	HDD base 65 deviation from normal for given jurisdiction
H35(Suffix)	HDD base 35 deviation from normal for given jurisdiction
T65(Suffix)	THI DD base 65 deviation from normal for given jurisdiction
T75(Suffix)	THI DD base 75 deviation from normal for given jurisdiction

Monthly Binary Variables

Jan	Binary variable for the month of January
Feb	Binary variable for the month of February
Mar	Binary variable for the month of March
Apr	Binary variable for the month of April
May	Binary variable for the month of May
Jun	Binary variable for the month of June
Jul	Binary variable for the month of July
Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December
CSS(month)	Binary variable representing change in billing system in 1996

Xcel Energy used internal and external data to create its MWh sales forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. An electric price series for each customer class was developed by calculating revenue per Mwh also based on billing information for each jurisdiction.

Weather data (dry bulb temperature and dew points) are collected from a local meteorologist and the National Oceanic and Atmospheric Administration (NOAA) for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days were calculated internally based on this weather data.

Economic and demographic data was obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from Global Insights, Inc. data banks, and reflect the most recent values of those series at time of modeling.

B.8 Data Adjustments and Assumptions

1. Weather Adjustments. Xcel Energy adjusted its weather data to reflect billing schedules. Therefore, the weather data corresponds exactly with the billing month schedule.

2. Economic Adjustments. All price data and related economic series were deflated to 1996 constant dollars.

Most of the data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for most data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's 2002 Long Range median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by Global Insights, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Electric Price Assumption. Xcel Energy incorporates estimates of resource adjustments in its price forecast, and anticipates little price-induced substitution between electric and natural gas or oil.

3. Weather Assumption. Xcel Energy assumed "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1983-2002. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

4. Loss Factor Assumptions. The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historic average loss factor for each legal entity, and assumes it will not change in the future.

Electrical consumption and number of customers for farm and mining sectors is not available historically and is not generated by Xcel Energy in preparing the forecast. No specific assumptions were made regarding the availability of alternate sources of energy.

Xcel Energy ran embedded models to see how much energy conservation is already implicit in the forecast models. The results of these models indicated that conservation (both energy and demand) is already captured in the modeling process.   The concept of "embedded conservation" has been discussed in detail and approved by the MN Department of Public Service during Xcel Energy's 1995 Integrated Resource Plan filing.

The concept behind "embedded" conservation is that as our DSM programs mature, the impact and momentum of past programs is already captured in our observed historical series. The historic sales, energy and peak data series are net of conservation programs that date back to 1985. In other words, a portion of our future conservation efforts is already captured by our time series modeling processes. Hence, the impact of a continuing conservation program is embedded in this data and the model results.

The conservation in our DSM programs is growing more slowly than it has been in the past. The embedded model for energy shows that because energy conservation is not continuing to expand as it had in the past, we should not make any adjustments in our energy or peak forecasts. Hence, we assume that the models already captured all future energy conservation efforts.

B.9 Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to the Mid-Continent Area Power Pool (MAPP) as a requirement of membership. MAPP then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Wisconsin Public Service Commission as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

B.10 Blue Lake Certificate of Need - Data Set

Xcel Energy
Certificate of Need Filing
Median Forecast (50 Percentile)

Annual Electrical Consumption (Mwh)

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	Total	Losses and Company Use	Total Native Requirements
2004	NA	NA	11,847,727	16,821,001	NA	11,902,791	180,144	1,018,632	41,770,295	3,982,598	45,752,894
2005	NA	NA	12,056,428	17,115,936	NA	12,118,704	180,618	1,039,960	42,511,646	4,053,651	46,565,297
2006	NA	NA	12,309,391	17,434,706	NA	12,329,130	180,905	1,060,241	43,314,373	4,129,640	47,444,013
2007	NA	NA	12,596,904	17,796,488	NA	12,555,660	181,008	1,076,214	44,206,273	4,213,830	48,420,103
2008	NA	NA	12,888,447	18,155,233	NA	12,790,521	181,008	1,095,535	45,110,745	4,299,600	49,410,345
2009	NA	NA	13,156,855	18,477,697	NA	13,010,370	181,008	1,102,427	45,928,357	4,376,921	50,305,278
2010	NA	NA	13,480,101	18,861,434	NA	13,257,556	181,008	1,102,427	46,882,525	4,467,463	51,349,989
2011	NA	NA	13,779,564	19,223,531	NA	13,499,186	181,008	1,102,427	47,785,716	4,552,719	52,338,435
2012	NA	NA	14,077,068	19,587,362	NA	13,741,172	181,008	1,102,441	48,689,051	4,638,308	53,327,359
2013	NA	NA	14,375,131	19,942,336	NA	13,986,504	181,008	1,102,427	49,587,405	4,723,188	54,310,593
2014	NA	NA	14,686,083	20,308,300	NA	14,228,338	181,008	1,102,427	50,506,156	4,810,216	55,316,373
2015	NA	NA	15,010,198	20,668,152	NA	14,453,490	181,008	1,102,427	51,415,275	4,896,302	56,311,577
2016	NA	NA	15,333,008	21,028,404	NA	14,680,905	181,008	1,102,441	52,325,766	4,982,550	57,308,317
2017	NA	NA	15,614,546	21,353,263	NA	14,902,748	181,008	1,102,427	53,153,992	5,061,042	58,215,034
2018	NA	NA	15,884,905	21,665,421	NA	15,120,062	181,008	1,102,427	53,953,824	5,136,777	59,090,601

Number of Customers

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	Total
2004	NA	NA	1,395,475	178,395	NA	793	4,339	2,857	1,581,859
2005	NA	NA	1,411,393	180,950	NA	805	4,503	2,856	1,600,507
2006	NA	NA	1,427,307	183,498	NA	815	4,668	2,857	1,619,145
2007	NA	NA	1,446,300	186,505	NA	826	4,869	2,857	1,641,357
2008	NA	NA	1,460,213	188,786	NA	836	5,007	2,857	1,657,699
2009	NA	NA	1,473,880	191,008	NA	843	5,142	2,857	1,673,730
2010	NA	NA	1,488,623	193,447	NA	854	5,293	2,857	1,691,074
2011	NA	NA	1,502,683	195,774	NA	863	5,436	2,857	1,707,613
2012	NA	NA	1,514,662	197,804	NA	870	5,554	2,857	1,721,747
2013	NA	NA	1,527,230	199,928	NA	876	5,682	2,857	1,736,573
2014	NA	NA	1,540,108	202,088	NA	882	5,814	2,857	1,751,749
2015	NA	NA	1,552,992	204,253	NA	888	5,947	2,857	1,766,937
2016	NA	NA	1,565,222	206,329	NA	893	6,073	2,857	1,781,374
2017	NA	NA	1,576,813	208,310	NA	898	6,190	2,857	1,795,068
2018	NA	NA	1,587,575	210,172	NA	903	6,298	2,857	1,807,805

Xcel Energy
Certificate of Need Filing
Median Forecast (50 Percentile)

Annual Base Peak Demand (Mw) by Customer Class

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	System Base Peak Demand
2004	NA	NA	3,315	3,326	NA	2,298	0	234	9,173
2005	NA	NA	3,380	3,391	NA	2,344	0	239	9,355
2006	NA	NA	3,455	3,459	NA	2,388	0	244	9,546
2007	NA	NA	3,543	3,538	NA	2,437	0	248	9,766
2008	NA	NA	3,622	3,605	NA	2,480	0	253	9,960
2009	NA	NA	3,693	3,665	NA	2,520	0	254	10,132
2010	NA	NA	3,776	3,734	NA	2,562	0	253	10,326
2011	NA	NA	3,854	3,800	NA	2,605	0	253	10,512
2012	NA	NA	3,932	3,866	NA	2,648	0	253	10,698
2013	NA	NA	4,001	3,922	NA	2,686	0	252	10,861
2014	NA	NA	4,078	3,985	NA	2,726	0	251	11,041
2015	NA	NA	4,159	4,047	NA	2,763	0	251	11,220
2016	NA	NA	4,239	4,108	NA	2,800	0	250	11,398
2017	NA	NA	4,309	4,165	NA	2,838	0	250	11,561
2018	NA	NA	4,376	4,218	NA	2,874	0	249	11,718

Xcel Energy
Certificate of Need Filing
Median Forecast (50 Percentile)

Monthly Base Peak Demand (Mw) and Load Factors

	Native Energy Requirements (Mwh)	Base Peak Demand (Mw)	Load Factor
January-04	3,905,465	6,527	80.4%
February-04	3,612,105	6,320	82.1%
March-04	3,552,302	5,983	79.8%
April-04	3,415,855	5,834	81.3%
May-04	3,592,406	6,818	70.8%
June-04	3,896,371	8,494	63.7%
July-04	4,588,953	9,173	67.2%
August-04	4,387,879	8,706	67.7%
September-04	3,706,602	7,921	65.0%
October-04	3,661,547	6,204	79.3%
November-04	3,580,396	6,333	78.5%
December-04	3,853,012	6,657	77.8%
January-05	3,977,577	6,540	81.7%
February-05	3,631,826	6,376	84.8%
March-05	3,628,782	6,052	80.6%
April-05	3,486,412	5,914	81.9%
May-05	3,666,292	6,924	71.2%
June-05	3,969,330	8,624	63.9%
July-05	4,669,783	9,355	67.1%
August-05	4,461,872	8,884	67.5%
September-05	3,777,435	8,080	64.9%
October-05	3,731,665	6,268	80.0%
November-05	3,646,245	6,395	79.2%
December-05	3,918,075	6,722	78.3%
January-06	4,046,907	6,606	82.3%
February-06	3,698,371	6,445	85.4%
March-06	3,701,577	6,119	81.3%
April-06	3,556,133	5,983	82.6%
May-06	3,739,418	7,062	71.2%
June-06	4,045,323	8,776	64.0%
July-06	4,754,717	9,546	66.9%
August-06	4,543,657	9,071	67.3%
September-06	3,846,686	8,247	64.8%

October-06	3,805,986	6,338	80.7%
November-06	3,717,283	6,464	79.9%
December-06	3,987,951	6,793	78.9%
January-07	4,121,614	6,679	82.9%
February-07	3,770,032	6,517	86.1%
March-07	3,779,328	6,190	82.1%
April-07	3,632,569	6,056	83.3%
May-07	3,820,537	7,217	71.2%
June-07	4,128,586	8,947	64.1%
July-07	4,846,542	9,766	66.7%
August-07	4,634,143	9,287	67.1%
September-07	3,921,781	8,439	64.5%
October-07	3,893,383	6,416	81.6%
November-07	3,800,670	6,540	80.7%
December-07	4,070,919	6,872	79.6%
January-08	4,202,806	6,759	83.6%
February-08	3,867,168	6,598	84.2%
March-08	3,864,720	6,271	82.8%
April-08	3,713,371	6,139	84.0%
May-08	3,903,919	7,366	71.2%
June-08	4,218,389	9,109	64.3%
July-08	4,937,354	9,960	66.6%
August-08	4,721,332	9,476	67.0%
September-08	3,990,804	8,610	64.4%
October-08	3,970,695	6,498	82.1%
November-08	3,875,659	6,619	81.3%
December-08	4,144,128	6,952	80.1%
January-09	4,275,414	6,839	84.0%
February-09	3,919,673	6,674	87.4%
March-09	3,942,141	6,345	83.5%
April-09	3,786,774	6,214	84.6%
May-09	3,981,696	7,496	71.4%
June-09	4,294,266	9,249	64.5%
July-09	5,019,633	10,132	66.6%
August-09	4,803,886	9,645	66.9%
September-09	4,066,796	8,763	64.5%
October-09	4,049,332	6,570	82.8%
November-09	3,949,165	6,690	82.0%
December-09	4,216,503	7,024	80.7%

January-10	4,353,318	6,913	84.6%
February-10	3,995,600	6,748	88.1%
March-10	4,024,665	6,419	84.3%
April-10	3,873,108	6,291	85.5%
May-10	4,071,928	7,638	71.7%
June-10	4,386,397	9,404	64.8%
July-10	5,118,541	10,326	66.6%
August-10	4,901,134	9,836	67.0%
September-10	4,150,215	8,935	64.5%
October-10	4,139,508	6,653	83.6%
November-10	4,035,201	6,772	82.8%
December-10	4,300,373	7,108	81.3%
January-11	4,435,716	6,999	85.2%
February-11	4,076,302	6,833	88.8%
March-11	4,112,741	6,503	85.0%
April-11	3,952,574	6,376	86.1%
May-11	4,154,952	7,781	71.8%
June-11	4,471,188	9,557	65.0%
July-11	5,208,252	10,512	66.6%
August-11	4,989,337	10,017	66.9%
September-11	4,225,796	9,099	64.5%
October-11	4,221,541	6,735	84.2%
November-11	4,113,344	6,852	83.4%
December-11	4,376,695	7,188	81.8%
January-12	4,514,047	7,079	85.7%
February-12	4,171,965	6,914	86.7%
March-12	4,195,406	6,582	85.7%
April-12	4,033,002	6,457	86.7%
May-12	4,237,949	7,923	71.9%
June-12	4,560,023	9,712	65.2%
July-12	5,299,577	10,698	66.6%
August-12	5,077,241	10,200	66.9%
September-12	4,295,732	9,264	64.4%
October-12	4,301,002	6,816	84.8%
November-12	4,190,208	6,931	84.0%
December-12	4,451,209	7,268	82.3%

January-13	4,591,577	7,160	86.2%
February-13	4,228,809	6,991	90.0%
March-13	4,279,038	6,658	86.4%
April-13	4,113,529	6,534	87.4%
May-13	4,323,083	8,049	72.2%
June-13	4,642,534	9,847	65.5%
July-13	5,390,217	10,861	66.7%
August-13	5,168,727	10,360	67.1%
September-13	4,380,321	9,411	64.6%
October-13	4,388,812	6,895	85.6%
November-13	4,272,468	7,009	84.7%
December-13	4,531,477	7,347	82.9%
January-14	4,672,204	7,240	86.7%
February-14	4,307,796	7,072	90.6%
March-14	4,365,249	6,739	87.1%
April-14	4,196,491	6,617	88.1%
May-14	4,409,740	8,187	72.4%
June-14	4,730,622	9,995	65.7%
July-14	5,482,495	11,041	66.7%
August-14	5,259,719	10,536	67.1%
September-14	4,458,613	9,571	64.7%
October-14	4,472,386	6,977	86.2%
November-14	4,352,121	7,089	85.3%
December-14	4,608,938	7,429	83.4%
January-15	4,751,588	7,322	87.2%
February-15	4,385,540	7,153	91.2%
March-15	4,450,082	6,819	87.7%
April-15	4,278,270	6,698	88.7%
May-15	4,495,106	8,325	72.6%
June-15	4,817,670	10,144	66.0%
July-15	5,573,895	11,220	66.8%
August-15	5,349,784	10,712	67.1%
September-15	4,536,029	9,730	64.7%
October-15	4,555,751	7,058	86.8%
November-15	4,431,645	7,168	85.9%
December-15	4,686,217	7,509	83.9%

January-16	4,831,552	7,404	87.7%
February-16	4,483,994	7,235	89.0%
March-16	4,535,169	6,900	88.3%
April-16	4,359,811	6,781	89.3%
May-16	4,579,309	8,462	72.7%
June-16	4,907,218	10,291	66.2%
July-16	5,664,583	11,398	66.8%
August-16	5,437,491	10,886	67.1%
September-16	4,605,880	9,888	64.7%
October-16	4,634,734	7,139	87.3%
November-16	4,508,244	7,248	86.4%
December-16	4,760,334	7,590	84.3%
January-17	4,905,913	7,484	88.1%
February-17	4,536,758	7,312	92.3%
March-17	4,615,031	6,975	88.9%
April-17	4,435,312	6,857	89.8%
May-17	4,659,341	8,589	72.9%
June-17	4,984,930	10,428	66.4%
July-17	5,747,950	11,561	66.8%
August-17	5,521,392	11,046	67.2%
September-17	4,683,641	10,034	64.8%
October-17	4,712,460	7,214	87.8%
November-17	4,580,932	7,320	86.9%
December-17	4,831,375	7,663	84.7%
January-18	4,977,117	7,558	88.5%
February-18	4,606,432	7,386	92.8%
March-18	4,691,189	7,048	89.5%
April-18	4,507,299	6,931	90.3%
May-18	4,734,553	8,711	73.1%
June-18	5,061,535	10,558	66.6%
July-18	5,827,925	11,718	66.8%
August-18	5,600,285	11,199	67.2%
September-18	4,751,548	10,172	64.9%
October-18	4,784,734	7,286	88.3%
November-18	4,649,712	7,390	87.4%
December-18	4,898,273	7,734	85.1%

Xcel Energy
Certificate of Need Filing
90 Percentile Forecast

Annual Native Energy Requirements (Mwh) and Base Peak Demand (Mw)

	Native Energy Requirements (Mwh)	Base Peak Demand (Mw)
2004	47,699,005	9,640
2005	48,567,036	9,856
2006	49,506,590	10,087
2007	50,560,304	10,359
2008	51,645,298	10,602
2009	52,628,851	10,821
2010	53,791,591	11,069
2011	54,903,653	11,308
2012	56,010,556	11,549
2013	57,108,668	11,748
2014	58,228,551	11,965
2015	59,336,671	12,183
2016	60,451,754	12,398
2017	61,471,829	12,598
2018	62,456,827	12,789

Xcel Energy
Certificate of Need Filing
80 Percentile Forecast

Annual Native Energy Requirements (Mwh) and Base Peak Demand (Mw)

	Native Energy Requirements (Mwh)	Base Peak Demand (Mw)
2004	47,017,866	9,476
2005	47,866,428	9,681
2006	48,784,688	9,898
2007	49,811,234	10,152
2008	50,863,064	10,377
2009	51,815,600	10,580
2010	52,937,030	10,809
2011	54,005,827	11,030
2012	55,071,437	11,251
2013	56,129,342	11,437
2014	57,209,289	11,642
2015	58,277,888	11,846
2016	59,351,551	12,048
2017	60,331,950	12,235
2018	61,278,648	12,414

B.11 Appendix Tables

Table B-1
Seasonal Firm Purchases - SUMMER
(MN Rules 7849.0280, Item B)

	NPPD	Mid America Energy	Manitoba Hydro	Minnesota Power	BEPC	Dairyland	IIGE	UE	EPMI	OPPD	MEC	Trans Alta	CMMPA	GRE	WAPA		
1993	70		600			4		75									749
1994			600	150		4											754
1995			350	200	40	4	50										644
1996			350	150		4					100						604
1997			350	150		4											504
1998	60		350	225		4			65	44	50						798
1999		50	350	175		4			30	56							665
2000			350	250					150			25					775
2001			350	85	50								15	75	2		577
2002			350		50									75	2		477
2003			350		50					35				75	2		512
2004			350		50									75	2		477
2005			350		50									75	2		477
2006			350		50									75	2		477
2007			350		50									75	2		477
2008			350		50									75	2		477
2009			350		50									75	2		477
2010			350		50									75	2		477
2011			350		50									75	2		477
2012			350		50									75	2		477
2013			350		50									75	2		477
2014			350		50									75	2		477
2015			200		50									75	2		327
2016			200		50									75	2		327
2017					50									75	2		127
2018					50									75	2		127

Table B-1
Seasonal Firm Purchases - WINTER
(MN Rules 7849.0280, Item B)

	Dairyland	MEC	MP	MH	GRE	BEPC	CMMPA	WAPA		
1993	4									4
1994	4									4
1995	4									4
1996	4									4
1997	4									4
1998	4									4
1999		200	25	50						275
2000					75	50	11			136
2001					75	50	12	2		139
2002								2		2
2003					75	50		2		127
2004					75	50		2		127
2005					75	50		2		127
2006					75	50		2		127
2007					75	50		2		127
2008					75	50		2		127
2009					75	50		2		127
2010					75	50		2		127
2011					75	50		2		127
2012					75	50		2		127
2013					75	50		2		127
2014					75	50		2		127
2015					75	50		2		127
2016					75	50		2		127
2017					75	50		2		127
2018					75	50		2		127

Table B-1
Seasonal Firm Sales - SUMMER
(MN Rules 7849.0280, Item B)

	WPS	Enron	Municipals	United Power	Wisconsin Rapids	Power Co.	Barron	EPMI	New Ulm		
1993			48	50		75					173
1994			49	50							99
1995			20								20
1996	100	45	19		15	100					279
1997			13		15	150					178
1998			14		15		7				36
1999			16	100	15		6				137
2000			13		15		8	150	15		201
2001			15								15
2002			15								15
2003			15								15
2004											0
2005											0
2006											0
2007											0
2008											0
2009											0
2010											0
2011											0
2012											0
2013											0
2014											0
2015											0
2016											0
2017											0
2018											0

Table B-1
Seasonal Firm Sales - WINTER
(MN Rules 7849.0280, Item B)

	Municipals	Manitoba Hydro	United Power	Wisconsin Rapids	Power Co.	CMMPA	Barron	Willmar		
1993	40		50							90
1994	41									41
1995	20	150	100							270
1996	18	350		15	100					483
1997	16	350	75	15		7		10		473
1998	18	350		15			6			389
1999	18	350		15			6			389
2000	11	350		15			8			384
2001	12	350								362
2002	15	350								365
2003	15	350								365
2004	15	350								365
2005	15	350								365
2006	15	350								365
2007	15	350								365
2008	15	350								365
2009	15	350								365
2010	15	350								365
2011	15	350								365
2012	15	350								365
2013	15	350								365
2014	15	350								365
2015	15	200								215
2016	15									15
2017	15									15
2018	15									15

Table B-2
Seasonal Participation Purchases - SUMMER
(MN Rules 7849.0280, Item C)

	Forecasted Short Term	All Source	Biomass	MPC Young	MPC Coyote	Otter Tail Power	Wisc Pub Svc	Non Utility	Manitoba Hydro	Barron	Minnkota Power Coop	United Power Assoc	Rochester
1993				50		75	138	94	500	4	50	22	
1994				50	150	75	98	95	650	4	50		70
1995				50	150	75	64	101	800	4	100	50	
1996				50	150	75	50	110	750	4	100	50	
1997				50	150	75		328	500	4		50	
1998				50	150	75		356	500	4		50	
1999				50	150	75		360	725	4		50	
2000				50	150	75		360	675	4		50	
2001					150	75		365	700		20	50	
2002				20	100	75		364	600			50	
2003					100	75		385	760			50	
2004	329				100	75		385	700			50	
2005	600	171	10		100			385	500			50	
2006	500	675	60		100			385	500			50	
2007	500	971	95		100			385	500			50	
2008	400	971	95		100			385	500			50	
2009	400	971	95		100			385	500				
2010	400	971	95		100			385	500				
2011	400	971	95		100			345	500				
2012	400	971	95		100			345	500				
2013	400	971	95		100			345	500				
2014	400	971	95		100			342	500				
2015	400	971	95		100			342					
2016	400	971	95					342					
2017	400	971	95					334					
2018	400	971	95					301					

	OPPD	Bepc	MDU	CMMPA	UCU	WRI	WPS	Ameren	Madelia
1993									
1994									
1995									
1996									
1997									
1998									8
1999	40	50	10	5	35	100	73	150	8
2000				2		50		100	8
2001						83		100	8
2002					10				
2003	10			25					
2004				25					
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									

	Kansas Power & Light	Mid America	WEP	MBMP	Aquila	EPMI	AEMC	UCU	RES	NIPSCO	DYPM	CIPCO	MPX	BHPI	GSE	HUC	KCPL	MEC	SRE	TEA	WEI	MP	
1993																							933
1994																							1242
1995																							1394
1996																							1339
1997	50	50																					1257
1998	50		120	10																			1373
1999																							1885
2000					98	100	20																1742
2001						100	48	100	50	50	100	25	15										2039
2002							235	50			150			40	20	6	25	150	50	30		50	2025
2003							255				100							150		20	61	100	2091
2004					235													150			61		2110
2005																							1816
2006																							2270
2007																							2601
2008																							2501
2009																							2451
2010																							2451
2011																							2411
2012																							2411
2013																							2411
2014																							2408
2015																							1908
2016																							1808
2017																							1800
2018																							1767

Table B-2
Seasonal Participation Purchases - WINTER
(MN Rules 7849.0280, Item C)

	Short Term	All Source	Biomass	Wisc Pub Svc	Non Utility	Manitoba Hydro	United Power Assoc	Barron	Madelia	CMMPA	Ameren	DYPM	MP	WRI	MPC	MEC	
1993					93	500	22										615
1994				150	103												253
1995				150	98	500											748
1996				150	111	500											761
1997				150	374	500											1024
1998					375	500		4									879
1999					377	500		4	8								889
2000					377	500		4	8	2	100	100					1091
2001					373	500		4				100	50	61			1088
2002					377	500		4		25		100			20	50	1076
2003					396	500				25			100				1021
2004					396	500											896
2005		171			396	500											1067
2006		675	60		396	500											1631
2007		971	95		396	500											1962
2008		971	95		396	500											1962
2009		971	95		396	500											1962
2010		971	95		396	500											1962
2011		971	95		356	500											1922
2012		971	95		356	500											1922
2013		971	95		356	500											1922
2014		971	95		353												1419
2015		971	95		353												1419
2016		971	95		350												1416
2017		971	95		312												1378
2018		971	95		312												1378

Table B-2
Seasonal Participation Sales - SUMMER
(MN Rules 7849.0280, Item C)

	Wisc Power Assoc	MGE	Melrose	Union Electric	WEPCO	OPPD	WPS	OTP		
1993		25								25
1994	150	25		100						275
1995	150			150						300
1996	150									150
1997										0
1998	126		3		250					379
1999			3		250	50	176			479
2000			3				186	50		239
2001			3				200			203
2002							200			200
2003										0
2004										0
2005										0
2006										0
2007										0
2008										0
2009										0
2010										0
2011										0
2012										0
2013										0
2014										0
2015										0
2016										0
2017										0
2018										0

Table B-2
Seasonal Participation Sales - WINTER
(MN Rules 7849.0280, Item C)

	Otter Tail	Minnkota Power	United Power Assoc	Wisc Power Assoc	MGE	Melrose	Municipals	WEPCO		
1993	75	50			25					150
1994	75	50		150						275
1995	75	50	50	150						325
1996	75	50	50	150						325
1997	75	50	50	150		3				328
1998	75	50	50	150		3				328
1999	75	50	50			3		150		328
2000	75	50	50			3				178
2001	75		50				10			135
2002	75		50							125
2003	75		50			3				128
2004			50			3				53
2005			50							50
2006			50							50
2007			50							50
2008			50							50
2009			50							50
2010										0
2011										0
2012										0
2013										0
2014										0
2015										0
2016										0
2017										0
2018										0

Table B-3
Load and Generating Capacity Data Excluding Plants Needing a CON - SUMMER
(MN Rules 7849.0280, Item D)

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
1993	6990	6990	969	173	6194	6194	6816	896	25	7687	929	7123	564
1994	7101	7101	754	100	6447	6447	6859	1532	175	8216	967	7414	802
1995	7519	7519	644	42	6917	6917	7100	1528	300	8328	1038	7955	373
1996	7487	7487	604	175	7058	7058	7110	1353	150	8313	1059	8117	196
1997	7353	7353	504	209	7058	7058	7118	1365	0	8483	1059	8117	366
1998	7626	7626	798	37	6865	6865	7150	1373	379	8144	1030	7895	249
1999	7990	7990	665	137	7462	7462	7187	1885	479	8593	1119	8581	12
2000	7936	7936	775	201	7362	7362	7243	1742	239	8746	1104	8466	280
2001	8349	8349	577	15	7787	7787	7153	2039	203	8988	1168	8955	34
2002	8239	8349	477	15	7777	7887	7275	2025	200	9100	1183	8960	140
2003	8289	8289	512	15	7792	7792	7273	2091	0	9364	1169	8961	403
2004	8680	8680	477	0	8203	8203	7304	2110	0	9414	1230	9433	-19
2005	8848	8848	477	0	8371	8371	7309	1816	0	9124	1256	9626	-502
2006	9033	9033	477	0	8556	8556	7314	2270	0	9583	1283	9839	-256
2007	9262	9262	477	0	8785	8785	7314	2601	0	9914	1318	10102	-188
2008	9470	9470	477	0	8993	8993	7559	2501	0	10059	1349	10342	-282
2009	9654	9654	477	0	9177	9177	7611	2451	0	10061	1377	10553	-492
2010	9865	9865	477	0	9388	9388	7611	2451	0	10061	1408	10796	-735
2011	10071	10071	477	0	9594	9594	7611	2411	0	10021	1439	11033	-1012
2012	10280	10280	477	0	9803	9803	7611	2411	0	10021	1470	11273	-1252
2013	10447	10447	477	0	9970	9970	7611	2411	0	10021	1495	11465	-1444
2014	10633	10633	477	0	10156	10156	7611	2408	0	10018	1523	11679	-1661
2015	10821	10821	327	0	10494	10494	7611	1908	0	9518	1574	12068	-2550
2016	11006	11006	327	0	10679	10679	7611	1808	0	9418	1602	12281	-2862
2017	11177	11177	127	0	11050	11050	7611	1800	0	9411	1657	12707	-3296
2018	11341	11341	127	0	11214	11214	7611	1767	0	9377	1682	12896	-3519

NOTES :
1. Forecasted demand values based on a 90% forecast level.
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April

Table B-3
Load and Generating Capacity Data Excluding Plants Needing a CON - WINTER
(MN Rules 7849.0280, Item D)

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
1993	5841	6990	4	97	5934	7083	7135	615	150	7600	1062	6996	604
1994	5838	7101	4	47	5881	7144	7382	756	275	7863	1072	6953	910
1995	6081	7519	4	271	6348	7786	7253	748	325	7676	1168	7516	160
1996	5869	7487	4	175	6040	7658	7367	761	325	7803	1195	7235	568
1997	5877	7353	4	209	6082	7558	7406	1032	328	8110	1174	7256	854
1998	6187	7626	4	37	6220	7659	7482	875	328	8029	1202	7422	607
1999	6422	7990	275	389	6536	8104	7537	889	328	8098	1216	7752	346
2000	6516	7936	136	384	6764	8184	7534	1091	178	8446	1228	7992	455
2001	6187	8349	139	362	6410	8572	7491	1088	135	8444	1286	7695	748
2002	6386	8239	2	365	6749	8602	7738	1076	125	8689	1290	8039	650
2003	6537	8289	127	365	6775	8527	7718	1021	128	8611	1279	8054	557
2004	6657	8680	127	365	6894	8918	7718	896	53	8561	1338	8232	329
2005	6722	8848	127	365	6960	9086	7722	1067	50	8739	1363	8323	417
2006	6793	9033	127	365	7031	9271	7727	1631	50	9308	1391	8421	887
2007	6872	9262	127	365	7109	9500	7727	1962	50	9639	1425	8534	1105
2008	6952	9470	127	365	7189	9708	7972	1962	50	9884	1456	8645	1239
2009	7024	9654	127	365	7262	9892	8024	1962	50	9936	1484	8745	1191
2010	7108	9865	127	365	7346	10103	8024	1962	0	9986	1515	8861	1125
2011	7188	10071	127	365	7426	10309	8024	1922	0	9946	1546	8972	974
2012	7268	10280	127	365	7506	10518	8024	1922	0	9946	1578	9083	863
2013	7347	10447	127	365	7585	10685	8024	1922	0	9946	1603	9188	758
2014	7429	10633	127	365	7666	10871	8024	1419	0	9443	1631	9297	146
2015	7509	10821	127	215	7597	10909	8024	1419	0	9443	1636	9233	210
2016	7590	11006	127	15	7477	10894	8024	1416	0	9440	1634	9111	328
2017	7663	11177	127	15	7551	11065	8024	1378	0	9402	1660	9210	192
2018	7734	11341	127	15	7621	11229	8024	1378	0	9402	1684	9306	96

NOTES :
1. Forecasted demand values based on a median forecast level.
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April

Table B-4
Load and Generating Capacity Data Including Plants Needing a CON - SUMMER
(MN Rules 7849.0280, Item E)

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
1993	6990	6990	969	173	6194	6194	6816	896	25	7687	929	7123	564
1994	7101	7101	754	100	6447	6447	6859	1532	175	8216	967	7414	802
1995	7519	7519	644	42	6917	6917	7100	1528	300	8328	1038	7955	373
1996	7487	7487	604	175	7058	7058	7110	1353	150	8313	1059	8117	196
1997	7353	7353	504	209	7058	7058	7118	1365	0	8483	1059	8117	366
1998	7626	7626	798	37	6865	6865	7150	1373	379	8144	1030	7895	249
1999	7990	7990	665	137	7462	7462	7187	1885	479	8593	1119	8581	12
2000	7936	7936	775	201	7362	7362	7243	1742	239	8746	1104	8466	280
2001	8349	8349	577	15	7787	7787	7153	2039	203	8988	1168	8955	34
2002	8239	8349	477	15	7777	7887	7275	2025	200	9100	1183	8960	140
2003	8289	8289	512	15	7792	7792	7273	2091	0	9364	1169	8961	403
2004	8680	8680	477	0	8203	8203	7296	2110	0	9406	1230	9433	-27
2005	8848	8848	477	0	8371	8371	7762	1816	0	9577	1256	9626	-49
2006	9033	9033	477	0	8556	8556	7767	2270	0	10036	1283	9839	197
2007	9262	9262	477	0	8785	8785	7767	2601	0	10367	1318	10102	265
2008	9470	9470	477	0	8993	8993	8012	2501	0	10512	1349	10342	171
2009	9654	9654	477	0	9177	9177	8064	2451	0	10514	1377	10553	-39
2010	9865	9865	477	0	9388	9388	8064	2451	0	10514	1408	10796	-282
2011	10071	10071	477	0	9594	9594	8064	2411	0	10474	1439	11033	-559
2012	10280	10280	477	0	9803	9803	8064	2411	0	10474	1470	11273	-799
2013	10447	10447	477	0	9970	9970	8064	2411	0	10474	1495	11465	-991
2014	10633	10633	477	0	10156	10156	8064	2408	0	10471	1523	11679	-1208
2015	10821	10821	327	0	10494	10494	8064	1908	0	9971	1574	12068	-2097
2016	11006	11006	327	0	10679	10679	8064	1808	0	9871	1602	12281	-2409
2017	11177	11177	127	0	11050	11050	8064	1800	0	9864	1657	12707	-2843
2018	11341	11341	127	0	11214	11214	8064	1767	0	9830	1682	12896	-3066

NOTES :
1. Forecasted demand values based on a 90% forecast level.
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April

Table B-4
Load and Generating Capacity Data Including Plants Needing a CON - WINTER
(MN Rules 7849.0280, Item E)

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
1993	5841	6990	4	97	5934	7083	7135	615	150	7600	1062	6996	604
1994	5838	7101	4	47	5881	7144	7382	756	275	7863	1072	6953	910
1995	6081	7519	4	271	6348	7786	7253	748	325	7676	1168	7516	160
1996	5869	7487	4	175	6040	7658	7367	761	325	7803	1195	7235	568
1997	5877	7353	4	209	6082	7558	7406	1032	328	8110	1174	7256	854
1998	6187	7626	4	37	6220	7659	7482	875	328	8029	1202	7422	607
1999	6422	7990	275	389	6536	8104	7537	889	328	8098	1216	7752	346
2000	6516	7936	136	384	6764	8184	7534	1091	178	8446	1228	7992	455
2001	6187	8349	139	362	6410	8572	7491	1088	135	8444	1286	7695	748
2002	6386	8239	2	365	6749	8602	7738	1076	125	8689	1290	8039	650
2003	6537	8289	127	365	6775	8527	8274	1021	128	9167	1279	8054	1113
2004	6657	8680	127	365	6894	8918	8274	896	53	9117	1338	8232	885
2005	6722	8848	127	365	6960	9086	8279	1067	50	9296	1363	8323	973
2006	6793	9033	127	365	7031	9271	8284	1631	50	9865	1391	8421	1443
2007	6872	9262	127	365	7109	9500	8284	1962	50	10196	1425	8534	1661
2008	6952	9470	127	365	7189	9708	8529	1962	50	10441	1456	8645	1795
2009	7024	9654	127	365	7262	9892	8581	1962	50	10493	1484	8745	1747
2010	7108	9865	127	365	7346	10103	8581	1962	0	10543	1515	8861	1681
2011	7188	10071	127	365	7426	10309	8581	1922	0	10503	1546	8972	1531
2012	7268	10280	127	365	7506	10518	8581	1922	0	10503	1578	9083	1419
2013	7347	10447	127	365	7585	10685	8581	1922	0	10503	1603	9188	1315
2014	7429	10633	127	365	7666	10871	8581	1419	0	10000	1631	9297	702
2015	7509	10821	127	215	7597	10909	8581	1419	0	10000	1636	9233	766
2016	7590	11006	127	15	7477	10894	8581	1416	0	9996	1634	9111	885
2017	7663	11177	127	15	7551	11065	8581	1378	0	9958	1660	9210	748
2018	7734	11341	127	15	7621	11229	8581	1378	0	9958	1684	9306	653

NOTES :
1. Forecasted demand values based on a median forecast level.
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April

Appendix C Demand Side Management Programs

Xcel Demand Side Management Programs

C.1 Responsibility for DSM

Debra Sundin, Director of Marketing in the Customer and Field Operations Business Unit, is responsible for Xcel Energy's demand-side management programs in Minnesota, Wisconsin, Colorado, North Dakota, and South Dakota.

C.2 Goals and Objectives

C.2.1 Xcel Energy's Energy Efficiency Goals

In its Order approving Xcel Energy's 2000 Resource Plan, the Commission adopted the demand-side management ("DSM") goal referred to as the 175 percent incentive scenario for the 2000-2014 planning period. This scenario established aggressive targets of 3,253 GWh of cumulative energy savings and 1,174 MW of cumulative peak demand savings in our Minnesota service territory over the planning period. The following table outlines the goals approved in the 2000 Resource Plan.

Table C1: DSM Goals Established In the 2000-2014 Integrated Resource Plan

Year	Total GWh	Total MW
2000	182	84
2001	176	84
2002	244	108
2003	231	90
2004	224	83
2005	225	80
2006	226	79
2007	223	77
2008	219	75
2009	215	68
2010	214	69

2011	213	68
2012	216	68
2013	219	69
2014	227	72
Total	**3,253**	**1,174**

The goals established by the Commission are implemented through the Conservation Improvement Program (CIP) administered by the Department of Commerce. Currently, the Company is operating under the incremental DSM goals established by the Commissioner of the Department of Commerce in our 2003/2004 CIP Biennial Plan. These goals are:

Table C2: 2003/2004 DSM Goals As Approved by the DOC in the 2003/2004 CIP Biennial Plan

	2003	2004	Total
Budget	$39,742,850	$41,071,147	$80,813,997
Generator kW	84,788	95,151	179,939
Generator kWh	208,613,828	207,690,815	416,304,643

As reported in the Company's annual CIP Status Reports filed with the Minnesota Department of Commerce, to date, Xcel Energy has exceeded its DSM goals established under the 2000 Resource Plan. In his decisions approving the Status Reports, the Commissioner notes that during the period of 2000 to 2002, the Company has exceeded its Resource Plan goals by 157 GWh (759 GWh achieved versus 602 GWh goal) and 99 MW (375 MW achieved versus 276 MW goal). [1]

However, the demand savings reported in the Company's CIP Status Reports should not be used for Resource Planning purposes. In the CIP Status Report, Xcel Energy reports the gross energy and demand savings achieved by the Company. The Status Report does not include any customers who

[1] See Commissioner Decision in *2000 Minnesota Natural Gas and Electric Conservation Improvement Program Status Report & Associated Compliance Filing, Oct. 2001,* Commissioner Decision in *2001 Minnesota Natural Gas and Electric Conservation Improvement Program Status Report & Associated Compliance Filing, Oct. 2002* Commissioner Decision in *2002 Minnesota Natural Gas and Electric Conservation Improvement Program Status Report & Associated Compliance Filing, Oct. 2003*.

may have left a load management program or those who may have reverted to less energy efficient equipment. Either of these two scenarios would reduce the actual amount of controllable load or conservation available to the Company in any given year. For Resource Planning purposes, it is necessary to consider Xcel Energy's net conservation and load management achievements.

Xcel Energy has only recently recognized a potential shortfall in DSM achievements due to a fall off in renewing load management contracts and is taking steps to increase its load management program performance in order to meet the Commission approved goals. For example, one such step is the proposed implementation of "Smart Switch" technology, a device developed by Xcel Energy's engineers and Cannon Technologies to increase the per participant load reduction in the Saver's Switch program. Xcel Energy will continue to look for opportunities to further increase demand savings from these programs in the coming years.

C.2.2 Xcel Energy's Energy Efficiency Objectives

Xcel Energy's objectives with respect to its conservation and load management efforts in Minnesota are to delay or avoid more expensive electric generation, reduce pollution, and help customers improve the efficiency with which they use energy. Xcel Energy strives to meet the legislative mandate to spend two percent of its gross electric operating revenues on energy efficiency programs and achieve the conservation levels outlined in the 2000 Resource Plan. The objectives of our current CIP Biennial Plan are to:

- Increase short-term program performance through modifications to current programs;
- Re-assess DSM and conservation market potentials;
- Evaluate specific program extensions and new concepts; and
- Work with other organizations to develop new program ideas.

C.3 Energy Efficiency Programs

C.3.1 Energy Efficiency Programs Considered

Xcel Energy operates 37 individual electric DSM programs in Minnesota targeted at our Commercial & Industrial, Small Business, Consumer, and Low-Income customer segments. These programs are designed to both meet the cost-effectiveness requirements established by law, and the specific goals/needs recognized by the Department of Commerce.

C.3.2 List of Energy Efficiency Programs

Table C3: Xcel Energy's 2003 Direct-Impact Electric DSM Programs

Program	Budget	Gen kW	Gen kWh	$/kW	$/kWh
Commercial & Industrial	**$15,764,359**	**38,620**	**158,804,702**	**$408**	**$0.10**
Energy Analysis	$93,023	n/a	n/a	n/a	n/a
Energy Design Assistance	$6,880,000	11,353	51,166,057	$606	$0.13
Building Recommissioning	$650,000	1,356	6,112,826	$479	$0.11
Compressed Air	$489,620	1,357	11,084,162	$361	$0.04
Roofing	$189,000	882	695,429	$214	$0.27
Cooling	$1,690,510	3,382	6,079,718	$500	$0.28
Custom Efficiency	$1,440,574	4,423	24,298,765	$326	$0.06
Lighting	$1,948,201	6,617	34,069,171	$294	$0.06
Motors/ASDs	$1,061,024	2,821	18,659,461	$376	$0.06
Refrigeration	$550,000	751	6,222,097	$732	$0.09
Energy Financing	$91,240	n/a	n/a	n/a	n/a
Peak Controlled Rates	$391,361	4,281	328,824	$91	$1.19
Saver's Switch for Business	$289,806	1,396	88,192	$208	$3.29
Conservation Total	$14,898,929	32,943	158,387,685	$452	$0.09
Load Management Total	$681,167	5,677	417,016	$120	$1.63
Non-Impact Total	$184,263	n/a	n/a	n/a	n/a
Small Business	**$8,074,685**	**18,497**	**43,104,291**	**$437**	**$0.19**
Energy Analysis	$251,950	n/a	n/a	n/a	n/a
Energy Design Assistance	$328,112	839	3,781,839	$391	$0.09
Compressed Air	$94,877	374	3,052,787	$254	$0.03
Roofing	$441,000	2,057	1,622,667	$214	$0.27
Cooling	$250,000	399	631,961	$627	$0.40
Custom Efficiency	$275,510	781	4,288,017	$353	$0.06
EnSave	$525,265	292	4,337,913	$1,799	$0.12
Lighting	$1,515,238	3,052	14,985,021	$496	$0.10

Lamp Recycling	$89,753	n/a	n/a	n/a	n/a
CEE One-Stop	$2,300,000	1,589	7,930,700	$1,447	$0.29
Motors/ASDs	$81,880	222	1,283,604	$369	$0.06
Refrigeration	$50,000	75	622,210	$665	$0.08
Energy Financing	$78,511	n/a	n/a	n/a	n/a
Peak Controlled Rates	$85,901	719	56,059	$119	$1.53
Saver's Switch for Business	$1,706,688	8,098	511,514	$211	$3.34
Conservation Total	$5,861,882	7,799	30,268,105	$752	$0.19
Load Management Total	$1,792,589	8,818	567,573	$203	$3.16
Non-Impact Total	$420,214	n/a	n/a	n/a	n/a
Consumer	**$10,820,998**	**27,596**	**6,060,127**	**$392**	**$1.79**
Consumer Education	$300,493	n/a	n/a	n/a	n/a
Energy Star	$4,863,819	6,500	3,740,945	$748	$1.30
Home Energy Audits	$410,776	n/a	n/a	n/a	n/a
Energy Financing	$87,871	n/a	n/a	n/a	n/a
Home Lighting Direct Purchase	$220,000	69	1,717,813	$3,207	$0.13
Lamp Recycling	$178,904	n/a	n/a	n/a	n/a
Phillips Cooperative	$125,000	n/a	n/a	n/a	n/a
Saver's Switch	$4,634,135	21,028	601,369	$220	$7.71
Conservation Total	$5,083,819	6,568	5,458,758	$774	$0.93
Load Management Total	$4,634,135	21,028	601,369	$220	$7.71
Non-Impact Total	$1,103,044	n/a	n/a	n/a	n/a
Low-Income Energy Services	**$855,791**	**75**	**644,708**	**$11,386**	**$1.33**
Research, Planning & Development	**$4,227,017**	**n/a**	**n/a**	**n/a**	**n/a**
Total 2003 CIP	**$39,742,850**	**84,789**	**208,613,828**	**$447**	**$0.18**

C.3.3 Reasons Other Programs were not Implemented

On an on-going basis, the Company reviews its current DSM programs and considers additions to its portfolio on the basis of their cost effectiveness and ability to achieve a certain level of market response.

C.4 Major DSM Accomplishments

Xcel Energy is a nationally recognized leader in energy conservation and load management programs. Of late, the Company has received the following awards for its DSM programs:

- 2003 Governor's Award for Excellence in Waste and Pollution Prevention for the Center for Energy and Environment's One-Stop Efficiency Shop.
- 2003 American Council for an Energy Efficient Economy Exemplary natural gas conservation program for the Energy Design Assistance and Boiler Efficiency programs.
- 2002 American Council for an Energy Efficient Economy Exemplary electric conservation program for the Energy Design Assistance and Lighting programs.
- 2001 European Council for an Energy Efficient Economy Program Most Likely to Meet the Intent of the 2001 Kyoto Protocols in the Shortest Time for Energy Design Assistance.
- 2001 Minnesota Environmental Initiative Award for the entire CIP Plan.

In addition, the Company has successfully managed a cost-effective DSM program for more than 10 years. Xcel Energy typically exceeds energy efficiency goals established by the DOC. Since 1990, the cumulative impact of these efforts is:

- Over $450 million in electric CIP expenditures;
- Over $1.8 billion in net benefits to society;
- Over 1,700 MW of demand-savings; and
- Over 3,100 GWh of energy-savings.

C.5 Future Plans

As discussed, the Company is operating under the guidelines established by the 2000 IRP.

C.6 DSM Programs Impact on Forecast Demand

C.6.1 Quantify how these programs determine the forecast provided in response to 7849.0270, subpart 2.

The goals established by the Commission have been incorporated into our forecasting analysis. As discussed in Section 5, the forecasted annual peak demand for electricity has been reduced by existing levels of load management and by cumulative DSM goals presented in Table C1 above.

C.6.2 Total Costs by Program

The estimated costs of our 2003 programs are provided in Table C3, above. Because the Company does not track its customers in the categories listed (farm, irrigation, nonfarm residential, commercial, industrial, mining, street and highway lighting, electrified transportation, and other), we are unable to provide information specific to those customer groups. However, in general, the listed categories fall into the following customer segments:

- Commercial & Industrial includes Commercial, Industrial, Mining;
- Small Business includes Street and Highway Lighting and Electrified Transportation;
- Consumer and/or Low-Income includes Nonfarm Residential.

C.6.3 Expected Effects in Reducing the Need for New Transmission and Generation.

Xcel Energy's programs follow the aggressive goals established in the 2000 IRP process. The effects of the Company's conservation and load management programs are incorporated into the forecast of energy and demand. Interruptible load (associated with interruptible and direct load control programs) is subtracted from the base peak demand forecast to obtain the "net generator peak" forecast.

Appendix D Alternative Technologies Screening

Alternative Technologies Screening

This screening of generation technology alternative starts with a brief description of the technology. The typical application, availability, and reliability of each technology are discussed next. Then, economic and environmental impacts typically associated with the technology are discussed.

D.1 Screening Factors

D.1.1 Applicability

Applicability of the technology refers to the technology's appropriateness for the Project's operating mode. One of the objectives of the Project is to provide capacity for peak load service. Other service modes include base load and intermediate load. Certain technologies are better suited for particular service modes. For example, large boiler facilities are well suited for base load and, in some cases, intermediate load service but not peaking service because of the long lead time necessary to bring a coal-fired plant on-line at full capacity.

D.1.2 Availability

Availability of generation typically refers to the percentage of time during any given year that the facility would be available for service. The North American Electric Reliability Council (NERC) defines availability as follows[2]:

> *"A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it is actually in service. Typically, this measure is expressed as a percent available for the period under consideration."*

The availability of an alternative is dependent upon maintenance requirements and availability of fuel, among other factors. For a facility designed to meet peak load demands, such as the Project, availability is typically not a concern as long as scheduled maintenance times are discretionary and can be scheduled around the peak demand periods.

[2] North American Reliability Council, "Glossary of Terms", www.nerc.com/glossary/, December 1999.

The evaluation of the proposed Project and alternatives must also address the commercial availability of a particular alternative technology—one that has been commercially demonstrated to meet needs similar to those the Project has been designed to serve.

The time from deciding to proceed with the development of an alternative until the facility is ready for commercial operation is the alternative's implementation time and is an availability consideration. The primary activities that affect implementation time are obtaining necessary regulatory approvals, negotiating financing agreements, selecting and acquiring a site, design and engineering, procuring, construction, and testing facility equipment.

D.1.3 Reliability

Reliability is the overall ability of an alternative to enhance the reliability of the bulk electric system. Reliability impact may be measured by an alternative's potential to reduce the frequency, duration and magnitude of adverse effects on the electric supply.

NERC defines reliability as follows[3]:

> *"The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system adequacy and security.*
>
> *Adequacy—the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking in account scheduled and reasonably expected unscheduled outages of system elements.*
>
> *Security—the ability of the electric system to withstand sudden disturbance such as electric short circuits or unanticipated loss of system elements."*

[3] Ibid.

D.1.4 Environmental Impacts

Environmental impacts refer to the effects the alternative is expected to have on the environment. Potential environmental impacts associated with generation technologies include air emissions, effects on land, water consumption, wastewater generation, noise, aesthetics, and traffic.

One measure of potential overall impact to the environment is the efficiency of the technology. Energy efficiency quantifies how completely one form of energy can be transformed into another form of energy that is more useful for a given purpose. Typically, for fossil fuel electric power generating facilities, efficiency is expressed in terms of a heat rate.

"Heat rate" is defined as[4]:

> *"a measure of average thermal efficiency of an electric generating facility expressed as the ratio of input energy per net kilowatt hour produced, computed by dividing the total energy content of fuel burned for electricity generation by the resulting net kilowatt hour generation."*

This heat rate can be converted into an efficiency (expressed as a percentage) by dividing 3413 by the heat rate (given in units of British thermal units per kilowatt-hour) and multiplying the results by 100. "Heat rate" and "efficiency" are inversely related (i.e., the lower the heat rate, the higher the efficiency). Therefore, energy conversion projects with lower heat rates are more efficient consumers of energy resources.

While heat rate or efficiency is not a direct measure of environmental impacts, a more efficient technology many times uses less of our natural resources and has lower environmental impacts (e.g., fewer air emissions) per kilowatt-hour of energy produced.

D.1.5 Economic effects

Economic effects of the alternatives may include jobs created during construction and during ongoing operations, effects on regional economic development, and effects on tax revenues generated.

[4] Minnesota Rules 7849.0010, Subp. 12.

D.2 Coal-Fired Boiler

A coal-fired steam power plant consists of a steam generation side and an electric generating side. In the simplest terms, steam is generated when water is heated by the thermal energy in pulverized coal that is released when coal is burned in the boiler. The steam from the boiler is piped to, and drives, a steam turbine, which in turn drives an electric generator.

The pulverized coal plant includes the following components:

- A large boiler that combusts coal and generates steam.
- A steam turbine generator that converts the steam's thermal energy into electrical energy.
- A coal handling system that provides coal to the boiler.
- A water treatment system that provides high quality water to the boiler steam cycle.
- A system (e.g., condenser or cooling tower) to cool the water that is used to condense the exhaust steam from the steam turbine generator.
- Air pollution control equipment required to meet State and Federal standards governing flue gas emissions.
- An ash disposal system that collects and disposes of waste ash from the coal combustion process.
- Distributed control systems to control plant equipment.
- Operations and maintenance buildings.

The fuel for the plant (coal) is typically brought to the plant by railroad or barge. Natural gas is often used as a secondary fuel and is transported to the facility via pipeline. A significant source of cooling water is required for condensing the exhaust steam from the steam turbine generator and for quenching ash produced in the boiler.

D.2.1 Applicability

A coal-fired facility may serve as an intermediate load unit; however, coal-fired power plants are best suited for base load (steady, high-capacity) duty. Coal-fired units are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a coal-fired plant on-line at full capacity.

D.2.2 Availability

Coal-fired power plants typically expect an annual outage rate for maintenance of 11 percent. Unplanned outages typically consume another 4 percent of the unit's availability. The net availability of coal-fired units is expected to be in the range of 85 percent.[5]

D.2.3 Reliability

A coal-fired plant can generally demonstrate high reliability (both the adequacy and security aspects).

D.2.4 Environmental Impacts

Viewing environmental impacts indirectly in terms of energy efficiency (input fuel energy per kilowatt hour produced), coal-fired plants typically operate in a range of 32 to 35 percent efficiency.[5] The direct environmental impacts of coal burning include air emissions, solid waste (ash) generation, waste heat discharge to air and water, and rail traffic.

D.2.5 Economic Effects

The total capital requirement for a hypothetical coal-fired power plant is estimated to be $1,100/kW[6]. A typical energy cost for a hypothetical coal-fired power plant is estimated to be 3.5 cents per kW-hour.[7] Building a coal-fired power plant is a major construction project with a 24- to 36-month or longer time frame. While the construction work force is of a significant size, its contribution to the local economy is temporary. Power plants in today's market are operating with significantly fewer

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[5] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, Exhibits 1-6, pages 8-18 to 8-26.

[6] CCPI Round 2 Planning Workshop, Pittsburgh, PA, August 26,2003, Coal Power Program Roadmap, National Energy Technology Laboratory, Kenneth Markel, Jr.

[7] National Energy Technology Laboratory, 8/26/03, Coal Power Program Roadmap

staff than in the past and are probably not regarded as having a key impact on local employment rates. Power plants in Minnesota are assessed a significant local property tax that can be viewed as likely offsetting the tax burden on other local enterprise.

D.3 Natural Gas-Fired Combined Cycle

A gas-fired combined cycle power plant is a combination of combustion turbine technology, heat recovery and electric generation. In the combustion turbine, incoming air is compressed and mixed with the natural gas fuel. Igniting this mixture results in an expansion of gases (the combustion products and excess air) through a power turbine that in turn drives an electric generator. Hot exhaust gases exiting the combustion turbine pass through a heat recovery steam generator (HRSG) to produce steam that is used to drive a steam turbine connected to a second electric generator. Typically, of the overall electric output from a combined cycle unit, two-thirds is produced by the combustion turbine and the steam turbine generator produces one-third.[8]

Other major combined-cycle plant equipment would include:

- a system (e.g., condenser or cooling tower) to condense the steam turbine exhaust steam;
- a water treatment equipment to provide high-quality makeup water to the steam cycle;
- electrical switchgear to provide power to auxiliary plant equipment;
- water storage tanks and fuel oil storage tanks (if applicable);
- natural gas vaporizers;
- possible ammonia storage if post-combustion NOx control is required; and,
- operations and maintenance buildings.

D.3.1 Applicability

Combined cycle plants are well suited to meet the intermediate load needs. Secondary service modes of base load and peak load are also achievable. A combined cycle plant is more economical to keep on heated standby than a coal-fired boiler would be. A combined cycle plant has a shorter construction period compared to a coal-fired plant.

[8] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, page 8-64.

D.3.2 Availability

Combustion turbine-based power generation can expect to reflect a planned outage rate of about 7 percent and an unplanned outage rate of about 5 percent. However, properly operated and maintained combined-cycle facilities will achieve 90 to 95 percent availability.[9]

D.3.3 Reliability

A combined-cycle plant can generally demonstrate high reliability (both the adequacy and security aspects). Natural gas-fired combined cycle facilities typically have fuel oil backup to address the potential interruption of natural gas supply.

D.3.4 Environmental Impacts

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced), show distinct advantages for a combined-cycle project vs. a coal-fired plant. The energy efficiency for a combined cycle plant can be expected to be in the range of 45 to 50 percent. The direct environmental impacts of operating a combined-cycle plant burning natural gas include air emissions, wastewater discharge, waste heat discharge to air and water and the potential for on-site ammonia storage if post-combustion NOx control is required. The combustion of a low sulfur, clean fuel instead of coal results in much lower levels of air emissions and eliminates ash generation and disposal.

D.3.5 Economic Effects

The total capital requirement for a hypothetical gas-fired combined-cycle power plant is estimated to be $590/kW[10]. A typical energy cost for a hypothetical gas-fired combined cycle power plant is estimated to be 4.6 cents per kW-hour[11]. Building a combined-cycle power plant is a major construction project with a 12- to 24-month time frame. While the construction work force is sizeable, its contribution to the local economy is temporary. A combined-cycle unit fired with pipeline natural gas will require significantly fewer staff than a corresponding coal-fired facility having to deal with major coal and ash handling operations. Thus, a combined cycle plant is not

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[9] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, page 8-68.

[10] Energy Information Administration, Derivatives and Risk Management in the Petroleum, Natural Gas, and Electricity Industries, October 2002, Appendix B, p. 75.

[11] California Energy Commission, 2/26/2003, Publication 100-03-001SD

regarded as having a key impact on long-term local employment rates. A combined cycle plant would be subject to applicable property tax assessments.

D.4 Dual-Fired Simple Cycle

The dual-fired simple cycle power plant uses natural gas as its primary fuel and uses fuel oil as a backup fuel for use during times of gas supply interruption. The dual-fired simple cycle power plant is similar to the technology described in Sections 5.2.1.2 for natural-gas fired combined cycle except that the heat from the combustion turbine exhaust gases is not recovered for secondary electric generation from a steam turbine. Because of this difference, simple cycle technology has a significantly lower efficiency than combined cycle technology. Ancillary equipment is likely limited to:

- natural gas vaporizers;
- possible ammonia storage if post-combustion NOx control is required;
- control buildings;
- fuel oil storage tanks;
- a fuel forwarding system (pumps/piping/controls) to transfer fuel oil from storage to the turbine; and,
- fuel heating systems for winter operations.

D.4.1 Applicability

Simple cycle plants are typically employed for peaking duty and are not well suited to economically meet intermediate and base load needs. Simple cycle turbine generators exceeding a 20 to 30 percent capacity factor would likely defer to intermediate load facilities or be considered for conversion to a combined cycle unit. Advantages of simple cycle turbine generators include flexibility in citing, relatively low capital cost and, as discussed with combined cycle plants, a relatively short construction period.

D.4.2 Availability

Simple cycle turbine-based power generation can expect to reflect a planned outage rate of about 7 percent and an unplanned outage rate of about 5 percent. However, properly operated and maintained turbine facilities will achieve 90 to 95 percent availability.[12]

D.4.3 Reliability

At the expense of economics, a simple cycle plant can generally demonstrate high reliability (both the adequacy and security aspects). A dual-fired simple cycle facility typically has fuel oil backup to address the potential interruption of natural gas supply.

D.4.4 Environmental Impacts

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced), would not show a distinct advantage for a simple cycle turbine-driven project vs. a combined-cycle plant or a coal-fired plant. The energy efficiency for simple cycle turbine generator can be expected to be in the range of 25 to 30 percent. The direct environmental impacts of operating a simple cycle plant burning natural gas include air emissions, waste heat discharge via the stack and the potential for on-site ammonia storage if post-combustion NO_x control is required.

D.4.5 Economic Effects

The total capital requirement for a hypothetical simple-cycle gas-fired combustion turbine power plant installation is estimated to be in the range of $544 to $816/kW[13]. Typical energy cost for a hypothetical simple-cycle gas-fired combustion turbine power plant is estimated to be 14.1 cents per kW-hour.[10] Building a simple cycle power plant is a major construction project with about a 12-month time frame. The positive impact of the construction work force on the local economy is temporary. A simple cycle unit fired with pipeline natural gas will require significantly fewer staff than a corresponding coal-fired facility having to deal with major coal and ash handling operations. Thus a simple cycle plant could not be regarded as having a key impact on long-term local

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[12] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, page 8-68.

[13] Northwest Power Planning Council, New Resource Characterization for the Fifth Power Plan, Natural Gas Simple-Cycle Gas Turbine Power Plants, May 20, 2002 (www.nwcouncil.org/energy/powerplan/grac/052202/gassimple.htm)

employment rates. Certain components of a simple cycle driven power plant would be subject to local property tax assessments.

Renewable Resource Technology Screening

D.5 Wind

Wind energy technology consists of a set of wind-driven turbine blades that turn a mechanical shaft coupled to a generator, which in turn produces electricity. The major components of the wind turbine include:

- the rotor blades;
- gear box;
- generator;
- nacelle (gearbox/generator housing); and,
- tower.

Wind turbines are either horizontal access or vertical access machines, which make full use of lift-generating air flows. Each type of turbine has advantages and disadvantages. Most types are commercially available, although the horizontal access turbine is predominant. Horizontal access turbines are typically built with two or three turbine blades. Turbines for utility applications are normally installed in clusters of 5 to 50 megawatts, and may be referred to as wind farms.

D.5.1 Applicability

Applicability for wind turbines is defined primarily by problems with reliability of the plant's "fuel", the wind. A wind turbine installation cannot adequately meet intermediate and peaking load needs. The variable nature of wind patterns does not support a strategy to address the growing demand for electric power in the near term. Siting of a large wind turbine installation is also predicated on locating candidate areas that have wind energy data that would support the project economics.

D.5.2 Availability

Whether or not the wind blows, wind turbines are generally expected to have an availability in the high 90-percent range (i.e., the turbines are capable of providing generating service).[14] Even when wind energy is present, wind turbines can only generate power within an optimum range of wind speeds.

D.5.3 Reliability

A wind turbine installation cannot have an objective of providing a guaranteed performance from the perspective of the utility customer. At best, wind-generated power can replace a percentage of baseload generation during periods of optimum wind conditions and subsequently conserve fossil fuels.

D.5.4 Environmental Impacts

Wind turbine generation has many environmental advantages over fossil fuels because there are no air emissions nor solids or water discharges associated with operating the turbines. Turbines may encounter some siting opposition with regard to noise and aesthetics. In many cases, the original use of the land (i.e., agriculture) can continue in the presence of the turbine installation.

D.5.5 Economic Effects

The total capital requirement for a hypothetical wind turbine installation is estimated to be in the range of $1,000/kW[15]. Typical energy cost for a hypothetical wind turbine is estimated to be 5.4 cents per kW-hour.[10] Building a wind farm project, like other power projects, would utilize a significant work force for the duration of construction. Operating a wind farm does not require a large staff. Wind power electricity often qualifies for tax credits or production incentives on a cents-per-kilowatt basis. [16]

D.6 Solar

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[14] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, page 8-106
[15] California DER guide, 12/8/03, http://www.energy.ca.gov/distgen/equipment/wind/cost.html.
[16] California DER guide, 12/8/03, http://www.energy.ca.gov/distgen/equipment/wind/cost.html.

Solar energy to electricity conversion technologies include thermal conversion (typically using sunlight to generate steam to turn a turbine) and photovoltaic (direct conversion of sunlight to direct current power). Thermal, or concentrating solar power technology (parabolic troughs, power towers, and dish/engine systems), converts sunlight into electricity efficiently with minimal effects on the environment. Trough systems predominate among today's commercial solar-powered plants.

Trough systems focus the sun at 30 to 60 times its normal intensity to heat a heat transfer fluid (synthetic oil). The hot oil is pumped to a generating station heat exchanger to produce steam. Finally, electricity is produced in conventional steam turbine generators. Trough systems may be configured as hybrids to operate on natural gas on cloudy days or after dark. Natural gas provides 25 percent of the output of the Barstow plants.

The "photovoltaic effect" is the basic physical process through which a photovoltaic (PV) cell converts sunlight into electricity. Solar energy (composed of photons) is transferred to the electrons of atoms making up the PV cell. Higher energy electrons begin to flow and become electric current. By grouping single PV cells into arrays, and then placing many arrays together, power plants of up to 6.5 megawatts have been built.

D.6.1 Applicability

Like wind turbine generation, the applicability for solar generation is defined primarily by problems with reliability. Solar power systems generally represent even less capacity than a wind turbine installation and, combined with a dependence on quality insolation rates, cannot meet intermediate load and peaking service needs. The variable nature of solar intensity does not support a strategy to address the growing demand for electric power in the near term. Siting of a large solar power plant is also predicated on locating candidate areas that have the solar energy data that would support the project economics. The Southwest United States, rather than Minnesota, is the prime (usual) location for significant solar generation efforts.

D.6.2 Availability

Whether or not the sun shines, solar power plants are generally expected to have an availability in the 90-percent range (i.e., the installations are capable of providing generating service if sufficient solar energy is present).[17]

D.6.3 Reliability

A solar power installation cannot meet an objective of providing a guaranteed performance to the end user of generated power. The hybrid design of some solar plants, utilizing natural gas during periods of poor solar intensity, acknowledges that solar energy cannot be depended upon to maintain a capacity rating.

D.6.4 Environmental Impacts

Solar power generation has many environmental advantages over fossil fuels because there are no air emissions or solids discharges associated with operating the systems. Trough/gas hybrid systems do utilize a steam loop, which requires process and cooling water, some water treatment and some wastewater discharge (blowdown).

D.6.5 Economic Effects

The total capital requirement for a hypothetical photovoltaic power plant is estimated to be $4,000/kW[18]. Typical energy cost for a hypothetical photo voltaic power plant is estimated to be 48.4 cents per kW-hour.[10] A trough/gas hybrid plant is estimated to have a total capital requirement in the range of $3,240/kW[19]. Building a solar generation project, like other power projects, could utilize a significant work force for the duration of construction. Operating solar generation facilities does not require employing a large staff.

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[17] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, Exhibits 27-30; pages 8-98 through 8-103.

[18] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, Exhibits 27-29, pages 8-98 to 8-100.

[19] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, Exhibit 30; page 8-103.

D.7 Biomass (Direct-Fired)

The process of direct-firing biomass fuels is very similar to the firing of other solid fuels. Fuel handling and storage, fuel firing, ash handling and disposal, air emissions, water consumption, and wastewater management will have many similarities to coal-fired systems. The primary activity steps for a biomass plant include:

- Biomass fuel receiving;
- On-site processing (size reduction, drying, screening)
- Fuel storage/conveying
- Boiler (usually a stoker design)
- Ash and flue gas handling
- Air emission controls (baghouse/ESP for particulate; ammonia for NO_x control)
- Steam turbine
- Cooling tower.

Biomass fuels can be harvested from the forest, collected as waste materials from processing plants or agriculture, or grown in biomass plantations. Fuel may be shipped to the power plant by truck, rail or barge depending on the plant location and type. Fuel will generally be stockpiled as insurance against interruptions in supply. Depending on the fuel characteristics, drying and size reduction may be necessary prior to firing. Drying is sometimes accomplished by utilizing the heat from stack gases. Prepared fuel is fed to the furnace and the resulting heat is used to generate steam. The steam from the boiler is piped to, and drives, a steam turbine, which in turn drives an electric generator to produce saleable electrical power.

D.7.1 Applicability

A biomass facility may serve as an intermediate load unit; however, biomass-fired power boilers are best suited for base load (steady, high-capacity) duty. Stoker boilers are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a solid fuel-fired plant on-line at full capacity. The forest products and agriculture industries in Minnesota offer a wide variety of available biomass fuels.

D.7.2 Availability

Biomass power plants are expected to have an annual outage rate for maintenance of 10 percent. Unplanned outages typically consume another 5 percent of the unit's availability. The net availability of biomass-fired units is expected to be in the range of 85 percent.[20]

D.7.3 Reliability

A biomass-fired plant can generally demonstrate high reliability (both the adequacy and security aspects) for base load and intermediate load service. The supply of biomass fuel in quantities sufficient to generate power at the hundred MW level and higher will require development of a fuel collection plan; however, Minnesota's agricultural and silvacultural industries can likely support a reliable fuel supply.

D.7.4 Environmental Impacts

Waste streams from the furnace include stack gases, bottom ash, and boiler water blowdown.

Bottom ash produced in many biomass combustion plants is often of a quality that can be sold, or used as a soil conditioner/fertilizer due to the lack of many trace metals, which often contaminate coal ash. Boiler blowdown, along with other process wastewater streams, will typically be treated to remove solids, oils, and grease prior to discharge. Cooling water used to condense the steam exhausted from the turbine would most likely be cooled using a direct contact cooling tower. The use of a cooling tower represents a significant consumption of water.

The stack gases will contain particulate matter as well as gaseous pollutants. If a thermal drier with auxiliary firing is used, the drying step will increase energy use and environmental emissions. Typically, stack gases will pass through an air pollution control device where particulate matter is removed. A large new boiler will likely be required to also address the control of NOx and CO emissions.

Viewing environmental impacts indirectly in terms of energy efficiency (input fuel energy per kilowatt hour produced), biomass-fired plants typically operate in a range of 20 – 30 percent efficiency.[13] Biomass power production is affected by a greater variability in biomass fuel quality

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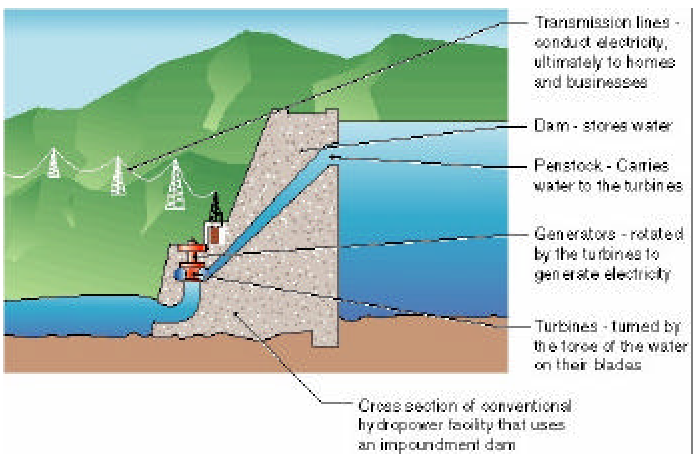
[20] TAG™ Technical Assessment Guide, Volume 1: Rev.7; EPRI TR-102276-V1R7, June 1993, Exhibits 35; page 8-120.

than is coal-fired power production. Variability in moisture and ash content are characteristic of a diverse fuel source and leads to variability in heat value on a mass basis. The direct environmental impacts of biomass burning are similar to those for coal combustion and include air emissions, solid waste (ash) generation, waste heat discharge to air and water, and truck and/or rail traffic.

D.7.5 Economic Effects

The total capital requirement for a hypothetical wood burning power plant is highly variable and size dependent. Higher capacity plants will generally be much cheaper. Capital costs are estimated to be in the range of $1,100 to $1,840/kW.[21] Typical energy cost for a wood burning power plant is estimated to be 4.9 cents per kW-hour.[22] Building a biomass-fired power plant is a major construction project with a 24 to 36 month or longer time frame. While the construction work force is of a significant size, its contribution to the local economy is temporary. The long-term operation of a biomass power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a (larger) biomass-for-fuel market may be an opportunity for farmers and landowners to exploit biomass materials that would otherwise be neglected as an income-producing source.



The plant would be subject to applicable property taxes that can be viewed as likely offsetting the tax burden on other local enterprise.

D.8 Hydropower

Hydropower is clearly the major player in the renewable group of power options accounting, for about 97 percent of renewable generation.[23] Hydroelectric power plants convert the potential energy

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[21] WTE Biomass Power Plant in Central Wisconsin, Energy Performance Systems, Inc., November 2000, Kenneth W. Ragland

[22] Wisconsin Energy Bureau, Final Report on Grant No. 89029, 11/2000

[23] EIA, Electric Power Monthly, March 1999, Table 5

of water, pooled at a higher elevation, into electricity by passing the water through a turbine and discharging it at a lower elevation. The water turns the turbine connected to an electric generator thus producing electrical energy. The turbines and generators are installed in, or adjacent to, dams, or use pipelines (called penstocks) to carry the pressurized water below the dam or diversion structure to the powerhouse. Hydropower projects are generally operated in a run-of-river, peaking, or storage mode.

Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and streamflow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases and power production to be more constant. Many projects combine the modes.

The capacity of a hydropower plant is primarily a function of two variables: (1) flow rate expressed in cubic feet per second (cfs); and (2) hydraulic head which is the elevation difference the water falls in passing from the reservoir through the turbine. Depending on the particular waterway being considered, project design may concentrate on either of these variables (high head/low flow or low head/high flow). Most conventional hydropower plants include the following major components:

- Dam — controls the flow of water and increases the elevation to create the heat. The reservoir that is formed is in effect stored energy.
- Penstock — carries water from the reservoir to the turbine in a power plant.
- Turbine — turned by the force of water pushing against the blades.
- Generator — connects to the turbine and rotates to produce the electrical energy.

The principal advantages of using hydropower are its large renewable domestic resource space, the absence of polluting emissions during operation, its capability in some cases to respond quickly to utility load demands, and its very low operating costs. Disadvantages can include high initial capital costs and potential site-specific and cumulative environmental impacts.

D.8.1 Applicability

Hydroelectric plants are operated in several modes. Plants with large water storage capability lend themselves well to peaking power production and hydroelectric plants are able to come on line much quicker than steam generating systems. Run-of-river plants are more likely to produce a more constant power output though that output is dependent on water levels and, in cold climates, ice conditions.

The U.S. Department of Energy's (DOE) Hydropower Program has developed an estimate of undeveloped hydropower in the United States.[24] The study and its model estimate a hydroelectric potential of about 2,500 MW to be available at more than 450 potential sites located within MAPP region states. Those potential megawatts come from additional capacity at existing hydro plants (about 800 MW), from existing dams not equipped with power generating equipment (about 1,200 MW), and from sites which would require dam construction (about 400 MW).

While it is possible that some of the identified potential hydropower could be developed, exploiting the potential requiring dam construction would need to also consider that transmission systems may not exist in remote areas containing hydropower potential. Development of hydropower, and associated transmission systems, faces the scrutiny of a general environmental trend toward releasing water reservoirs where possible. Developing capacity of a hundred MW or more would require development of multiple existing and/or potential hydropower sites. Such an effort would take several years of environmental study and negotiation to acquire water use and land rights, and permits and licensing for dams and/or transmission lines.

D.8.2 Availability

As discussed previously, there is potential for additional hydropower development within the MAPP region. It is unclear whether that potential can be practicably realized. The timetable to develop those resources is not likely to be able to meet near-term capacity and energy requirements.

During periods of normal precipitation and ice-free conditions, the availability of established hydropower generation is typically in the range of 95 percent.

D.8.3 Reliability

The hydropower sector of power generation is well established with proven technologies installed as standard design. In mechanical terms, hydroelectric plants are highly reliable.

[24] U.S. DOE Hydropower Program; http://www.inel.gov/national/hydropower/state/stateres.htm

Because hydropower depends on water flow, hydroelectric plants are susceptible to fluctuations in output as a function of weather patterns. Reliability can suffer during periods of drought or during periods of freezing conditions in northern climates. Weather-induced fluctuation in power output may be less pronounced than it is for wind or solar power; however, for long-term planning to meet projected demand, hydropower may be better suited to reliably provide peak load capacity.

D.8.4 Environmental Impacts

Hydropower projects are not sources of the typical air and water emissions and solid waste disposal issues associated with solid fuel-fired power production; however, hydropower has faced scrutiny for its significant environmental impacts. More recent projects benefited from early experience to be able to minimize or offset impacts of altered river basin hydrology, fish mortality, fish migration interference, decrease in water quality, and flooding of land.

D.8.5 Economic Effects

The total capital requirement for a hypothetical hydropower power plant is estimated to be \$2,000/kW.[25] Typical energy cost for a hypothetical hydropower plant is estimated to be 6.6 cents per kW-hour.[10] Most of the potential sites within MAPP have capability of less than 10 MW and economies of scale cannot be realized. Annual operating expenses would likely be less than for a fuel-fired power plant because the hydropower energy source (pooled water) is not typically a purchased input.

Building a hydroelectric power plant is a major construction project with a several-year time frame. While the construction work force is of a significant size, its contribution to the local economy is temporary. The long-term operation of a hydroelectric power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a new reservoir does have the potential for creating commerce from recreational activity if fisheries and surrounding land area are developed to attract the public.

D.9 Landfill Gas

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[25] Hydro Research Foundation, FAQ, www.hydrofoundation.ort/research/faq.html, 12/9/2003

The most common use of landfill gas (LFG) is for on-site electricity generation by firing stationary engine generator sets. Some LFG is used to fire boilers or turbines and LFG, sufficiently processed, could be an energy source for fuel cell operation. Electric generating plants using LFG and those using natural gas or distillate oil are nearly identical; however, firing LFG does require gas processing and careful monitoring of equipment because LFG tends to be more corrosive. Significant quantities of LFG are emitted from municipal solid waste where it has been deposited in landfills; however, LFG typically has a medium Btu content and is not typically a source of energy on a scale larger than a few MW.

LFG recovery for energy is practiced in the United States, Europe and other countries around the world. A typical system consists of the following components[26]:

- the gas collection system, typically a series of wells strategically placed throughout the landfill, which gathers the gas being produced within the landfill;
- the gas processing system and engine/generator set , which cleans the gas and converts it into electricity; and
- the interconnection equipment, which delivers the electricity from the project to the final user.

D.9.1 Applicability

LFG power generation projects are generally sited on large landfills and produce power in the range of kilowatts, perhaps 1 to 2 megawatts. The driver for LFG power generation is the utilization of a fuel source that would otherwise be flared to avoid an explosion hazard and to avoid an emission source by producing saleable energy. A LFG plant could reasonably be viewed as an emission control technology. LFG does not exist at the levels needed to support large energy needs.

[26] U.S. Department of Energy/National Renewable Energy Laboratory, a DOE national laboratory; DOE/CH10093-322; DE94006897; May 1994, Revised October 1994; http://www.eren.doe.gov/cities_counties/landfil1.html

D.9.2 Availability

The availability of a LFG-fired generation system is expected to be similar to systems firing natural gas (i.e., availability greater than 90 percent); however, the corrosive nature of landfill gas does introduce more potential for equipment problems.

D.9.3 Reliability

Because of the small-scale nature of most LFG plants, a LFG power installation project typically does not have an objective of providing a guaranteed performance from the perspective of the utility customer. Power output for LFG plants depends upon the LFG production rate that does not adjust to power demand. LFG-generated power can replace a percentage of baseload generation and subsequently conserve fossil fuels.

D.9.4 Environmental Impacts

LFG projects are expected to be a net benefit to the environment by reducing the amount of LFG emissions to the atmosphere; however, some of the landfill emission reductions are offset by the combustion emissions such as NO_x and CO from the combustion equipment. From an energy efficiency perspective, LFG collection systems (i.e., the well networks) are not totally efficient, and combined with the inherent inefficiencies of combustion equipment, the overall energy efficiency of an LFG system generally less than 30 percent.

D.9.5 Economic Effects

The total capital requirement for developing a hypothetical LFG power plant ranges from $1,100 to $1,700/kW[27]; however, the LFG volumes do not exist within one MAPP site necessary to fuel a plant with a hundred MW or higher capacity. Typical energy cost for a hypothetical LFG power plant is estimated to be 6.0 cents per kW-hour.[28] Annual operating expenses may be less than for a typical fuel-fired power plant because the LFG is not typically a purchased input; however, municipalities associated with landfills may require a royalty to be paid from energy sales.

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[27] Landfill Methane Outreach Program, Training Workshop, Sao Paulo, Brazil, June 25, 2001, Part 3: Conventional and Emerging Technology Applications for Utilizing Landfill Gas, Linda Nutting, SCS Engineers

[28] Landfill Gas Utilization Project, County of Santa Cruz, Institute of Electrical and Electronics Engineers, Inc., SF Chapter, March 20, 2003, Brown, Vence & Associates, Inc., Thomas Vence

The long-term operation of a LFG power plant would not be regarded as having a large impact on local employment rates via plant staffing.

Other Technologies Screening

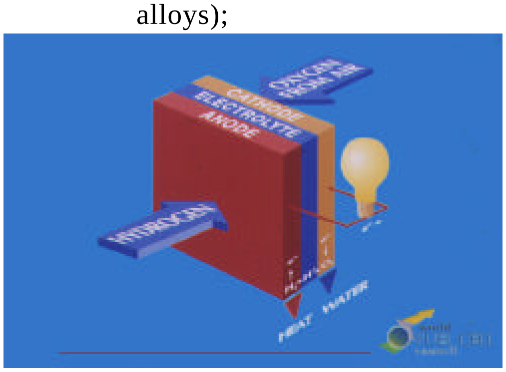
D.10 Fuel Cells

A fuel cell converts energy directly, without combustion, by combining hydrogen and oxygen electrochemically to produce water, electricity, and heat. Fueled with pure hydrogen, they produce no pollutant emissions. Even if fueled with natural gas as a source of hydrogen, emissions are orders of magnitude below those for conventional combustion generating equipment. The principle of operation of a typical fuel cell consists of the following processes:

- When hydrogen is fed into a fuel cell a catalyst on the anode converts hydrogen gas into negatively charged electrons (e^-) and positively charged ions (H^+).
- The electrons (e^-) flow through an external load to the cathode.
- The hydrogen ions (H^+) migrate through the electrolyte to the cathode where they combine with oxygen and the electrons (e^-) to produce water.

There are a variety of fuel cell designs (referring mainly to the electrolyte style) including solid oxide, alkaline, phosphoric acid, molten carbonate, and proton exchange membrane. The main components of a fuel cell system include:

- A porous anode (example materials are graphite, and nickel, chromium and zirconium alloys);



- An electrolyte (example phosphoric acid)
- A porous cathode (same materials as anode);
- Precious metal catalyst
- Fuel reformer (to generate hydrogen from fossil fuel)
- Power conditioner (to convert from DC to AC and to regulate power production in accordance with load).

D.10.1 Applicability

Fuel cell installations are viewed as an extended generation strategy and thus are typically sited adjoining the end user. Currently, a large fuel cell installation is in the range of 2 MW. The fuels, especially natural gas, potentially used by fuel cell installations are widely available.

D.10.2 Availability

Power industry estimates for significant fuel cell technology implementation range from 5 to 10 years. Demonstration units have achieved greater than 1 year of uninterrupted service. As design improves with experience, fuel cells will provide high availability.

D.10.3 Reliability

Fuel cells have demonstrated high reliability in pilot installation settings. Current manufacturing capacity of fuel cells is not yet established to the point where fuel cell installations are expected to address significant demand.

D.10.4 Environmental Impacts

Fuel cells can boast great potential for improving energy efficiency. Fuel cells generate significant quantities of waste heat that can be recovered in a cogeneration configuration. The proximity of fuel cells to the end user of generated power greatly reduces transmission losses.

Fuel cell environmental impacts directly related to operating the cell are minimal. By eliminating the combustion step of fossil fuel utilization, air emissions are virtually eliminated relative to conventional fuel-fired power generation. Indirect impacts may arise if a preliminary fuel processing step (e.g., coal gasification) is utilized to provide fuel for a fuel cell.

D.10.5 Economic Effects

The total capital requirement for developing a hypothetical fuel cell power plant is estimated to be \$4,000/kW[29]. Typical energy cost for a hypothetical fuel cell power plant is estimated to be 15.4 cents per kW-hour.[10] The size of fuel cell installations would require hundreds of fuel cell sites to provide capabilities in the range of a hundred MW or more. Fuel cells, individually, will require maintenance but will be too small to create a noticeable impact on local employment statistics.

[29] California DER guide, 12/8/03, www.energy.ca.gov/distgen/equipment/fuel_cells/cost.html

D.11 Microturbines

Microturbines are a type of combustion turbine that is used for stationary energy generation applications. They are usually small units (common refrigerator size) with outputs that vary from 25 to 1,000 kW. Microturbines operate similar to a combustion turbine (see Section G.3) except on a much smaller scale. Generally, microturbines contain the following design features:

- Radial flow compressors
- Low pressure ratios (single or possibly two stage compression)
- Minimal use of van or rotor cooling
- Recuperation of exhaust heat for air preheating
- Use of materials that are amenable to low cost production
- Very high rotational speeds on the primary output shaft (25,000 rpm or more)

Microturbines are capable of using many alternative/optional fuels including natural gas, diesel, ethanol, landfill gas, and other biomass-derived liquids and gases.

D.11.1 Applicability

Microturbines are well suited to meet intermediate, baseload, peaking, or co-generation load needs. High kW output needs may not be feasible because existing power conditioning equipment does not allow easy interconnection between microturbine systems.

D.11.2 Availability

Microturbines have relatively few moving parts and can operate continuously with little maintenance. Existing microturbine based power generation systems have demonstrated greater than 99 percent availability[30].

[30] [Microturbines: A Disruptive Technology, Chuck Tanner, Cogeneration and Competitive Power Journal, March 2000

D.11.3 Reliability

Microturbine systems can generally demonstrate high reliability (both the adequacy and security aspects). Natural gas-fired systems typically do no have alternative fuel options for backup. A reliable natural gas or other primary fuel source is required to have a reliable system.

D.11.4 Environmental Impacts

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced) show a distinct disadvantage versus combined-cycle and coal-fired plants. The energy efficiency for a microturbine system can be expected to be in the range of 15-30 percent.[31]

Direct environmental impacts of operating a natural gas combustion microturbine include air emissions and waste heat discharge. Microturbines have manufacturer listed NOx levels from 9 to 50 ppm (typical generator natural gas combustion sources range from 45-200 ppm NOx).[32]

D.11.5 Economic Effects

The total capital requirement for a hypothetical microturbine power plant is estimated to be in the range of $700 to $1,100/kW.[33] Typical energy cost for a hypothetical microturbine power plant is estimated to be 14.8 cents per kW-hour.[34]

Construction and installation of a microturbine system is estimated to be 6 to 18 months.[35] The construction work force is anticipated to be minimal. Average installation costs vary from $1,300 to $2,500 per kW.[26]

D.12 Energy Storage

The application of energy storage technologies to the problem of providing peaking power presumes that there is excess or underutilized generating capacity. Energy storage technologies have long been considered as a means of leveling the load on existing generating plants thus allowing them to operate closer to their peak efficiencies. Four storage technologies are discussed here - battery

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[31] California DER guide, 12/5/03, www.energy.ca.gov/distgen/equipment/microturbines/performance.html
[32] Ibid
[33] Ibid
[34] NRECA CRN – DOE Microturbine Demonstration Program, 3/13/2002, Arlington, VA
[35] Technology Characterization: Microturbines, EPA, March 2002

energy storage systems (BESS), compressed air energy storage (CAES), pumped storage hydroelectric, and flywheel energy storage.

Portions of the following discussion are based on information contained in the U.S. DOE/EPRI topical report on renewable energy technologies.[36]

Battery Energy Storage System (BESS) – There are currently a wide variety of types of batteries available for use in energy storage applications. In a chemical battery, charging causes reactions in electrochemical compounds to store energy charged to the battery in a chemical form. When a load is applied to the battery, reverse chemical reactions allow the energy to be drawn from the battery. Commercially available batteries range in size from kilowatts to modular configurations of several megawatts.

Compressed Air Energy Storage (CAES) – CAES plants are designed to use off-peak energy from existing power plants to compress air and store it in air-tight underground caverns. When called upon, the air is released, heated, and expanded through a gas turbine to recover the energy. Although manufacturers offer equipment to construct CAES systems ranging up to 350 MW, to date only a 110 MW plant has been constructed in Alabama. The Electric Power Research Institute (EPRI) has estimated that more than 85 percent of the United States may have geological characteristics which would allow for CAES construction.

Pumped Storage Hydroelectric – Pumped storage hydroelectric plants pump the water resource, usually through a reversible turbine, from a lower reservoir to an upper reservoir. While pumped storage facilities are net energy consumers, they are valued by a utility because they can be rapidly brought on-line to operate in a peak power production mode. The pumping to replenish the upper reservoir is performed during off-peak hours when electricity costs are lowest. This process benefits the utility by increasing the load factor and reducing the cycling of its base load units. In most cases, pumped storage plants run a full cycle every 24 hours.

Flywheel Energy Storage – The concept behind this technology is to store energy in a spinning flywheel. An integral motor/generator is connected to the flywheel and can be used to either charge energy to the flywheel or extract energy from it. This technology has been applied to mechanical systems and is now receiving attention towards applying it to electrical systems. Commercially available flywheels constructed of steel are limited in size due to the potential for catastrophic failure. Advanced composite wheels have been designed but are not yet commercially available. Small demonstration systems, rated in the kilowatt range, have been constructed. Large-scale application of the technology has not been demonstrated.

D.12.1 Applicability

Energy storage projects require an energy producer with excess or underutilized generating capacity to charge the storage system. Where this excess capacity exists, energy storage technologies are a means of leveling the load on existing generating plants thus allowing them to operate closer to their peak efficiencies.

D.12.2 Availability

By their nature, energy storage systems have high availability so that power may be readily extracted and used. Availability may be lessened if stored energy levels are reduced for any reason. Pumped storage hydroelectric energy may be unavailable during periods of high flows if water cannot be released from the impoundment to a receiving waterway.

Implementation times for the energy storage technologies discussed here would be variable due to the differences in issues between them. Small, disperse battery and flywheel systems could likely be installed within months, whereas CAES and pumped storage hydro facilities may require years of development effort likely involving contentious approval processes.

D.12.3 Reliability

As with availability, reliability is essentially a design feature of energy storage systems. These systems would typically back up less reliable parts of the overall electric supply system.

D.12.4 Environmental Effects

Quantitative values for efficiency of each system have not been identified. A feature of all storage systems is that less energy will be extracted than was originally stored. The process of storage requires an energy expenditure that cannot be recovered.

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[36] U.S. DOE and EPRI. December 1997. "Renewable Energy Technology Characterizations", EPRI Topical Report TR-109496, www.eren.doe.gov/utilities/techchar.htm.

None of the four systems discussed here will directly release air pollutant emissions in significant amounts. Pumped storage hydro development will have impacts similar to any hydroelectric project development. Substantial areas of land and habitat may be lost due to hydro development. None of the technologies discussed here would discharge significant quantities of wastewater or noise.

D.12.5 Economic Effects

The capital costs for constructing an energy storage facility are variable and dependent on technology selection. However, as noted previously, energy storage projects require an energy producer to charge the storage system. The costs for energy storage typically assume that underutilized energy production facilities exist. Operating costs are primarily dependent upon the operating costs associated with the original energy source.

The economic benefits derived from development of energy storage projects may be limited to minor increases in employment levels and property tax benefits.